Decision 14-11-002 November 6, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Golden State Water Company, on Behalf of its Bear Valley Electric Service Division (U913E), for Approval of Costs and Authority to Increase General Rates and Other Charges for Electric Service by Its Bear Valley Electric Service Division.	Application 12-02-013 (Filed February 16, 2012)

DECISION RESOLVING GENERAL RATE CASE OF GOLDEN STATE WATER COMPANY, ON BEHALF OF ITS BEAR VALLEY ELECTRIC SERVICE DIVISION

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DECISION RESOLVING GENERAL RATE CASE OF GOLDEN STATE WATER COMPANY, ON BEHALF OF ITS BEAR VALLEY ELECTRIC SERVICE DIVISION

Summary

Golden State Water Company, on behalf of its Bear Valley Electric Service District (GSWC/BVES) is authorized to increase rates by amounts designed to increase revenue by $1.2 million or 3% in its Test Year (TY) 2013, $0.4 million or 0.2% in 2014, $0.4 million or 0.2% in 2015, and $0.4 million or 0.2% in 2016. As a result of the revenue increase granted by this decision, the monthly bill for the average GSWC/BVES residential customers using 450 kilowatt hours per month would increase by $4.14 or 4.5% to $95.25 from $91.11 for the TY 2013 (*see* Appendices[1]).

The rates authorized for BVES in this General Rate Case allows BVES to meet its obligations pursuant to Public Utilities Code § 451, to take all actions "...necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

1. Background

On February 16, 2012, Golden State Water Company (GSWC), on behalf of its Bear Valley Electric Service District (BVES) filed Application (A.) 12-02-013 (or Application) to increase rates charged for electric service within its service

[1] Appendix A - Settlement Agreement Addressing All Outstanding Issues Except Cost Allocation and Rate Design; Appendix B - Cost Allocation and Residential Customer Rate Design Settlement Agreement; Appendix C – Adopted Base Rates; and Appendix D – Adopted Total Rates.

territory by 9.85%, which results in a proposed rate increase of 7.79%. On April 5, 2012, GSWC/BVES filed its Amended Application.

BVES is a wholly owned subsidiary of American States Water Company (ASWC), which is operated through another ASWC subsidiary, GSWC. BVES provides retail electric service to the Big Bear Lake resort area in the San Bernardino Mountains. The BVES service territory is a resort community, comprised primarily of residential customers. BVES provides service to approximately 23,300 customers, of which 21,900 are residential customers and approximately 1,400 are commercial, industrial, or public authority customers. BVES also provides service to two ski resorts in its territory. The BVES system is comprised of one 8.4 megawatt (MW) generation plant, 205 miles of overhead and 54 miles of underground conductors, and 13 substations. BVES's generation plant, the Bear Valley Power Plant (BVPP), began commercial operation in 2005 and is located at BVES's main office in Big Bear Lake. BVES's distribution facilities are located within the control area operated by the California Independent System Operator (CAISO), but are not directly interconnected with the CAISO-controlled high-voltage transmission grid. The BVES distribution system connects to the CAISO grid through transmission and distribution facilities owned, controlled, and operated by Southern California Edison Company (SCE).

On March 8, 2012, Resolution ALJ-176-3290 preliminarily determined that this proceeding was ratesetting and that hearings would be necessary. Protests were filed by Snow Summit, Inc. (Snow Summit) on March 21, 2012, by the Office of Ratepayer Advocates (ORA)[2] on March 23, 2012, and individually by Big Bear Area Regional Wastewater Agency (BBARWA) and the City of Big Bear Lake (City) on April 18, 2012. These protests were filed in response to the GSWC/BVES Application and Amended Application. GSWC/BVES filed responses to these protests on April 2, 2012 and April 20, 2012.

On April 17, 2012, the prehearing conference (PHC) took place in San Francisco to establish the service list for the proceeding, discuss the scope of the proceeding, and develop a procedural timetable for the management of the proceeding. Besides GSWC/BVES, parties to this proceeding include Snow Summit, ORA, BBARWA, and the City.

On April 26, 2012, GSWC/BVES filed a motion requesting authority to open a General Rate Case (GRC) Memorandum Account. ORA responded to this motion on May 11, 2012, and GSWC/BVES replied to the response on May 16, 2012. On August 2, 2012, the Commission issued Decision (D.) 12-08-006, in which it authorized GSWC/BVES to establish a GRC Memorandum Account.

On May 14, 2012, the assigned Commissioner issued her *Assigned Commissioner's Scoping Memo and Ruling* (Scoping Memo), which addressed the scope and schedule for this proceeding.

Two public participation hearings (PPHs) were held in Big Bear Lake on August 27, 2012. The primary concern of the customers that spoke was the level of GSWC/BVES's requested rate increase.

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[2] At this outset of this proceeding, ORA was referred to as the Division of Ratepayer Advocates or ORA. Since that time, this party changed its name. For consistency's sake, the Commission refers to this party as the Office of Ratepayer Advocates or ORA throughout this decision.

On September 17-19, 2012, Evidentiary Hearings (EH) were held. GSWC/BVES, ORA, and BBARWA/City presented witnesses in support of their respective testimonies.

On November 9, 2012, GSWC/BVES filed a motion requesting the reopening of the record, to which ORA and BBARWA/City replied on November 30, 2012. GSWC/BVES replied on December 7, 2012. ORA and BBARWA/City took no position as to whether the record should be reopened or not. On December 14, 2012, the assigned Administrative Law Judge (ALJ) issued an electronic mail (e-mail) ruling, in which she granted GSWC/BVES's motion to reopen the record, and also set a date, January 3, 2013, for a second PHC. GSWC/BVES and BBARWA/City each issued PHC statements on December 28, 2012. SCE requested party status in order to participate in this proceeding, based on its interest in the issue for which GSWC/BVES requested reopening of the record. The assigned ALJ granted SCE party status.

On January 7, 2013, the assigned Commissioner issued her Amended Assigned Commissioner's Scoping Memo and Ruling (Amended Scoping Memo), in which she addressed the limited scope and schedule for the second phase of this proceeding. The scope of this phase was limited to review and assessment of new information regarding GSWC/BVES's proposed undergrounding of poles on Big Bear Boulevard.

EH in the second phase of this proceeding took place on October 30, 2013. New information was included in GSWC/BVES's rebuttal testimony regarding contributions by other entities such as Verizon Communications (Verizon) to the costs associated with poles on Big Bear Boulevard. In order to provide parties with an opportunity to respond, the assigned ALJ informed parties at the EH, that they could file and serve opening and reply comments on this issue only.

GSWC/BVES and ORA filed and served their opening and reply comments on November 20 and 27, 2013, respectively.

Opening briefs addressing issues in both phases were filed on December 13, 2013 by GSWC/BVES, ORA, SCE, Snow Summit, and BBARWA/City. Reply briefs addressing issues in both phases were filed on December 23, 2013 by GSWC/BVES, ORA, SCE, Snow Summit, and BBARWA/City.[3]

On April 24, 2014, GSWC/BVES noticed a settlement conference for April 25, 2014 which would address all outstanding issues in the current proceeding except cost allocation and residential rate design. On April 28, 2014, GSWC/BVES noticed a settlement conference for May 6, 2014 which would address the issues of cost allocation and residential rate design. On May 2, 2014, GSWC/BVES requested (through e-mail) an extension to file settlements, by May 12, 2014. This request was granted through an e-mail ruling by the assigned ALJ on May 5, 2014.

On May 12, 2014, two motions were filed, one requesting adoption of a settlement regarding all outstanding issues in the current proceeding except cost allocation and residential rate design, and another requesting adoption of a settlement regarding cost allocation and residential rate design.[4] ORA filed comments against the Second Settlement Agreement on June 6, 2014. The

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[3] SCE's briefs were limited to the issue of poles on Big Bear Boulevard.

[4] The Joint Motion for Commission Approval and Adoption of Uncontested Settlement Agreement and the attached Settlement Agreement are referred to throughout as the First Settlement Agreement. The Joint Motion for Commission Approval and Adoption of Cost Allocation and Residential Customer Rate Design Settlement Agreement and the attached Settlement Agreement are referred to throughout as the Second Settlement Agreement.

Parties to the Second Settlement filed a reply to ORA's comments on June 20, 2014.

On July 31, 2014, this proceeding was submitted.

In determining the various components of BVES's authorized revenue requirement, we do not use a one-size-fits-all approach. Doing so would ignore the uniqueness of events and circumstances that affect each component of the revenue requirement determination. By, for example, just using a five-year average to estimate the base upon which a forecasted expense is determined, we would ignore an expert's estimate based on intimate knowledge of the utility or recent events. What if the increases over those five years grew to a greater extent in more recent years? An average would result in a lower growth factor that recent history indicated as the trend. Therefore, we consider all options presented by parties for estimating forecasted revenue requirement elements, using the method which most appropriately fits the circumstances of each element.

2. Joint Comparison Exhibit

The Joint Comparison Exhibits filed jointly on December 16, 2013 by GSWC/BVES, ORA, BBARWA/City, and Snow Summit provides a comparison of Test Year (TY) 2013 results of operations to show the differences between GSWC/BVES and ORA.

3. Overview of Parties' Positions

3.1. GSWC/BVES

In this Application, GSWC/BVES requests a TY 2013 increase of 9.85% in total revenues, which would result in a 7.79% increase in an average BVES electric bill rate. The requested increase in total revenues of $4.01 million (9.85%) from $40.69 million to $44.70 million, results in a bill increase of 7.79%, because

$860,000 of that proposed increase would come from sources other than regular electric bills. The proposed rate increase of 7.79% equates to an increase in the average residential bill in 2012 of approximately $7.56/month, resulting in an average residential bill at proposed rates of $104.62/month.

The requested $4.01 million increase in total revenues is driven primarily by: 1) a $1.64 million increase for GSWC general office (GO) allocations to BVES, as authorized in GSWC's 2010 GRC decision;[5] 2) a $1.05 million increase as a result of actual sales being substantially lower than the adopted sales forecast; and 3) $ 1.32 million increase due to its proposed increase for inflation and other factors from adopted 2012 rates to TY 2013.

GSWC/BVES also requests changes in its supply rate components; and plans to reduce its supply rates by approximately 5.5% when BVES's Purchased Power Adjustment Clause (PPAC) balance under-collection reaches zero in September 2014.

GSWC/BVES requests that BVES have the opportunity to earn a rate of return on rate base (ROR) of 9.81% for TY 2013, based on a 12.00% return on equity (ROE), and a capital structure of 44.4% long-term debt and 55.6% common equity. GSWC/BVES believes this request is reasonable and would assist it in attracting capital at a reasonable cost.

3.2. ORA

In this GRC, ORA is proposing one TY, 2013, with base revenue for the three years following TY 2013 to be determined by a formula that provides for annual increases. ORA recommends a $2.95 million decrease in Base Rates.

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[5] *See* D.10-11-035.

BVES is requesting base revenue increases of $1.88 million for 2014, $1.29 million for 2015, and $1.23 million for 2016. ORA is recommending revenue increases of $341,000 for 2014, $357,000 for 2015 and $364,000 for 2016.

BVES's request is made up of three separate items, though ORA states that only one, BVES's request for a $1.32 million increase to its 2012 authorized base rates, has not previously received Commission authorization.

ORA recommends a decrease in the average electric rate of 0.90%. The primary differences between BVES's request and ORA's recommendation are: 1) a $2.175 million reduction by ORA in the forecasts of plant investment; 2) a 154 basis point reduction by ORA in the ROR; and 3) a $7.726 million reduction by ORA in rate base.

3.3. Snow Summit

Snow Summit operates two ski resorts in Big Bear Lake – Snow Summit and Bear Mountain. Both ski resorts are customers of BVES. Snow Summit is the single largest customer of BVES. Snow Summit receives a portion of its energy needs from BVES, and generates the remainder itself. In total, Snow Summit, Inc. has 15 separate accounts with BVES - three are large power accounts pursuant to BVES's Tariff Schedule A-5 TOU Primary; and 12 accounts are pursuant to BVES's A-1, A-2, and A-3 commercial rate schedules. Snow Summit's main concerns regarding BVES's request are that: 1) BVES's incremental service ratemaking and revenue allocation proposal would raise costs above its cost of service; 2) BVES's proposed revenue proposal is over-stated, and there are errors in BVES's marginal cost study that would affect Snow Summit, Inc.; and 3) BVES's request for an increased ROE is unjustified given the reduction in the risk-free cost of capital since BVES's last ROE request, and BVES has not demonstrated an increase in shareholder risk since its last ROE request. Snow Summit recommends that BVES should be authorized a ROE of 8.39%, which would result in a reduction of $871,000 in BVES's requested revenue requirement.

3.4. BBARWA/City

During the pendency of this proceeding, BBARWA/City proposed that: 1) the Commission should reject BVES's proposed standby fee for BBARWA because such a fee is unjust, unreasonable, unsupported, and BBARWA/City have not relied on BVES for electricity for its wastewater treatment plant or received any meaningful standby service through its A5-TOU tariffs since 2008; 2) BVES believes that the poles on Big Bear Boulevard should be undergrounded, making use of the vaults and conduits installed by the City nearly 20 years ago, and results in an increase of just $0.107/month on each bill; and 3) the Commission should open an investigation to determine why so many poles on Big Bear Boulevard failed so fast, and hold revenues collected from customers to pay for the undergrounding of these poles in a memorandum account until the investigation is resolved.

3.5. SCE

SCE believes that pole loading is an issue of statewide importance, and supports the approval of GSWC/BVES's undergrounding project. In support of its position, SCE states that the undergrounding project should be approved because: 1) such approval would utilize assets previously installed using taxpayer money; 2) not undergrounding would harm both BVES and its ratepayers; 3) undergrounding provides the most benefits at the least costs of the various options being considered; 4) Verizon's contribution to pole maintenance is rightly based on the 1998 Joint Pole Agreement; 5) responsibility for payment of pole replacement in the current proceeding should not be guided by the

SCE-Safety Enforcement Division Settlement Agreement in the Malibu Canyon Fire Order Instituting Investigation; 6) BVES is not responsible for the overloading of its poles; and 7) a formal investigation into the failure of BVES's poles is more appropriately addressed in a statewide proceeding.

SCE also proposes that ORA's recommended $2 million increase to BVES's depreciation reserve balance should be rejected, as it is in violation of Generally Accepted Accounting Principles (GAAP). SCE also posits that since BVES has collected depreciation expense equal to the original cost of the plant in question (though over a shorter amount of time), there is no need to depreciate this fully depreciated plant any more.

4. Settlement Agreement Addressing All Outstanding Issues Except Cost Allocation and Rate Design

Pursuant to Rules 11.2 and 12.1(a),[6] GSWC/BVES, ORA, Snow Summit, and the City/BBARWA,[7] filed a motion on May 12, 2014 requesting approval and adoption of the First Settlement. In this same motion, GSWC/BVES state that SCE has authorized BVES to state that SCE will not oppose the Commission approving this settlement, thereby making the First Settlement unopposed. The issues addressed in the First Settlement are limited to all outstanding issues in

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[6] Pursuant to Rule 12.1, parties to a proceeding may file a written motion requesting adoption of a settlement, anytime after the first PHC and within 30 days after the last day of hearing. Rule 11.6 permits motions for extensions of time to comply with the Rules or an ALJ ruling. Prior to filing the Joint Motion in the current proceeding (which was filed more than 30 days after the last day of hearing), counsel for GSWC/BVES submitted a motion through e-mail to the assigned ALJ, requesting an extension of time to file a motion for approval of a settlement agreement in this proceeding. The assigned ALJ granted GSWC/BVES's motion by an e-mail ruling on May 5, 2014, to May 12, 2014.

[7] Referred to throughout this decision as *Parties to the First Settlement.*

this proceeding except for cost allocation issues and rate design principles for residential customers. Cost allocation issues and rate design principles for residential customers are addressed in the Second Settlement (*see* Section 7 herein).

In accordance with Rule 12.1(b), the Parties to the First Settlement convened a settlement conference on April 25, 2014. Notice and opportunity to participate were provided to all parties for the purpose of discussing a settlement in this proceeding. In their May 12, 2014 motion, the Parties to the First Settlement state that the First Settlement is reasonable, consistent with law, and in the public interest in accordance with Rule 12.1(d).

4.1. Base Rate Revenue Requirements

GSWC/BVES requested a TY 2013 base rate revenue requirement of $22,096,378 compared to ORA's recommendation of $18,147,968. The First Settlement provides for an overall base rate revenue requirement for TY 2013 of $19,700,000. The Parties to the First Settlement negotiated values for some but not all of the components of base rate revenue requirement. The specific components agreed to include: 1) A composite depreciation rate of 2.3%; 2) A capital additions budget of $2.5 million in 2013 and 2014 and $3.0 million in 2015 and 2016 (excluding the two Major Plant Additions discussed in Sections 5.6 and 5.7 herein); 3) An authorized ROE of 9.95% and a ROR of 8.60%; and 4) Allocated BVES Costs from GSWC's GRC.

4.2. Post Test-Year Adjustment Mechanism

BVES offered several different post-test-year adjustment mechanism (PTAM) proposals for 2014, 2015, and 2016, including one which increases the TY 2013 revenue requirements by approximately $1.883 million, $1.289 million, and $1.229 million for 2014, 2015 and 2016, respectively. ORA proposed a PTAM based upon the Urban Price Index for 2014, 2015 and 2016, with an offsetting productivity factor of 0.5%, which would result in increases of $341,180, $356,840 and $364,240 for 2014, 2015 and 2016, respectively.

The First Settlement provides for a revenue requirement increase of $400,000 for each of the years 2014-2016, resulting in base rate revenue requirements of $20,100,000, $20,500,000 and $20,900,000, for 2014, 2015, and 2016, respectively.

4.3. Authorized ROE and ROR

BVES requested a ROE of 11.71% and a ROR of 9.57%, while ORA recommended a ROE of 9.35% and a ROR of 8.27% and Snow Summit recommended a ROE of 8.39% with no recommendation on ROR.

The First Settlement provides a 2013 base rate revenue requirement of $19.7 million, which includes a ROE of 9.95% and a corresponding ROR of 8.60%.

4.4. Ongoing Authority to Use GO Allocation Update for Certain Costs

BVES requested authority to adjust revenue requirements through an advice letter (AL) process whenever the Commission authorizes a different allocation to BVES for GO costs, common plant allocations, or pension and benefits. ORA did not oppose the request to update GO costs, but: 1) recommended that common plant costs be updated along with GO allocations; and 2) opposed updating the pension and benefit costs through the GO allocation process.

The First Settlement provides that BVES may, on an ongoing basis, use the existing GO allocation process to update the following allocation of GSWC costs to BVES: (i) GSWC GO costs; (ii) GSWC common plant costs; and (iii) GSWC pension and benefit costs (collectively, the "Allocated BVES Costs"), each as approved by the Commission in a GSWC GRC decision.

To implement the update of the GO expense allocation, BVES would file a Tier 1 AL within 90 days of the date of a decision in a GSWC GRC that authorizes the adjustment of general office costs allocated to BVES.

4.5. Pension Balancing Account

BVES proposed a pension and benefit balancing account that would also include medical costs. ORA opposed the request and recommended either: 1) no balancing account; 2) a one-way balancing account; or 3) a cost-sharing balancing account mechanism between ratepayers and shareholders for expenses above the annual amounts authorized by the Commission.

The First Settlement provides that BVES may establish a Pension Balancing Account under the same terms and conditions as authorized by the Commission in D.13-05-011 for GSWC's pension and benefit balancing account. BVES is not allowed to establish a balancing account for medical expenses or other non-pension benefit costs during the subject rate cycle.

4.6. Major Capital Additions

BVES requested approval for $5.1 million to recover the costs of replacing the existing overhead lines along Big Bear Boulevard with underground wires[8] over the period 2013-2015. ORA and the City opposed the Big Bear Boulevard Undergrounding Project, ORA opposed the Office Expansion Project, ORA recommended that 2015 capital projects be recorded by Federal Energy Regulatory Committee (FERC) account, only instead of by project name. BVES

8 Referred to as the Big Bear Boulevard Underground Project.

agreed to withdraw its request for the Office Expansion Project and the North Shore 34 KV Reconductor Project.

BVES recommended approval in base rates for 2013 of a portion of the costs of the Big Bear Boulevard Underground Project and the Office Expansion Project. BVES also recommended the costs of the Moon Ridge Substation Upgrade and North Shore 34 KV Reconductor Project be included in base rates for 2015. BVES's proposed PTAM method would have recognized recovery of the post-2013 costs for all four of these major plant addition projects.

The First Settlement permits BVES to undertake the Big Bear Boulevard Underground Project (total settled cost of $7,032,540 plus Allowance for Funds Used During Construction (AFUDC)[9] and the Moon Ridge Substation Upgrade Project (total settled cost of $1,461,667 plus AFUDC).[10] These two Projects will not be funded through the base rate revenue requirements agreed to by the Parties to the First Settlement.[11] Instead, within 90 days of the completion and placement into commercial operation of the Moon Ridge Substation Upgrade Project, or any of the authorized phases of the Big Bear Boulevard Underground Project, BVES may file a Tier 1 AL requesting implementation of proposed new base rates for as much as the agreed-upon costs for each project plus accrued AFUDC at an annual rate of 6.69%. If the costs of the Big Bear Boulevard Underground Project or the Moon Ridge Substation Upgrade Project exceeds $7,032,540 (plus AFUDC) or $1,461,667 (plus AFUDC), respectively, BVES may

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[9] The agreed upon AFUDC rate in the First Settlement equals an annual rate of 6.69%.

[10] Combined, the Big Bear Boulevard Underground Project and the Moon Ridge Substation Upgrade Project are referred to as Projects.

[11] See First Settlement Agreement at 7 of the Joint Motion and 12-13 of the Settlement.

use a portion of its capital additions budget in the First Settlement (if approved) to cover the remaining costs in order to complete either of the Projects.

4.7. Solar Initiative Program

BVES requested a solar program with an overall budget of $1,462,500 in base rates, with a target capacity of 800 kilowatts (kW) to be achieved in four steps over a period up to eight years. ORA recommended a two-step program with a target capacity of 335 kW for a four-year period and a total budget of $546,000 in base rates.

The First Settlement provides for the establishment of an 800 kW solar initiative program (SI Program), which would be funded through the use of Public Purpose Program Surcharges. The SI Program would have a maximum overall cost of $1,286,350 over the eight-year term of the SI Program. BVES would also establish a one-way balancing account (the Solar Initiative Balancing Account) in which to track SI Program costs. BVES will include a summary of SI Program expenditures and achievements in its 2017 GRC application.

4.8. Energy Efficiency Program

BVES requested an energy efficiency program (EE Program) funding level of $230,000 a year in base rates. ORA recommended an EE Program funding level of $176,072 a year in base rates.

The First Settlement provides for an EE Program funding level of $200,000 per year, totaling $800,000 over the four-year rate case period, funding through the use of Public Purpose Program Surcharges, and establishment of a one-way balancing account (Energy Efficiency Balancing Account) to track EE Program costs.

4.9. Base Rate Design

In order to develop final rates, the allocation of costs (i.e., revenue requirements) to each customer class is necessary. The parties were unable to reach agreement regarding the allocation of costs to each customer class. The parties did, however, reach agreement on rate design principles for all customer classes except residential customers. The First Settlement provides that the rate design principles shall be applied in designing rates as follows:

1. First, apply the overall revenue requirement for 2013 of $19,700,000.
2. Next, allocate costs (i.e., assign a portion of the overall base revenue requirement) to each customer class (e.g., revenue allocation) as determined by the Commission. No cost allocation is included in the First Settlement.
3. Next, the Commission must determine the rate design principles for residential customers (e.g., permanent residential minimum charges and the percent change in base rates between Tier 1 and Tier 2, and Tier 2 and Tier 3).
4. Finally, apply the rate design principles noted above using the BVES rate design model in order to derive specific rates for each customer rate schedule. The BVES rate design model includes the agreed-upon forecast of customers and sales.

4.10. Confirmation of Power Supply Costs, Charges and Rate Design

BVES sought confirmation of selected amounts in its PPAC Balancing Account, and requested renaming of certain charges[12] and adjustment to the rates of certain charges.[13] ORA stated that it did not take issue with these requests.

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[12] The "Power Purchase Adjustment Clause" will be renamed the "Supply Adjustment Mechanism"; the "Power System Delivery Charge" will be renamed the "Transmission

Footnote continued on next page

4.11. Changes to Special Charges and Rules

BVES proposed a standby rate of $3.75/kW for A-5 TOU[14] customers and BBARWA rejected a standby charge for A-5 TOU customers. Parties to the First Settlement confirm that BVES may establish a new $10.50/kW standby service rate for customers taking service under Schedule A-4 TOU, and agree to a $1.50/kW standby rate for A-5 TOU secondary customers.

The Parties to the First Settlement confirm that BVES may increase various service and notice charges, including the service and reconnection charges, "turn off notices, clean and show charges, and a new late payment charge.

BVES's proposed modifications to Rule 2H are withdrawn by BVES.

The Parties to the First Settlement confirm that BVES may make changes in Rule 7, including a change regarding interest on deposit requirements and changes consistent with practices of other California electric utilities.

The Parties to the First Settlement confirm that BVES may make changes in Rule 20 undergrounding provisions to be consistent with other utility Rule 20 provisions.

The Parties to the First Settlement agree that base rates by customer class for 2013 should be developed as outlined in Section 8 of the First Settlement

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Charge"; the 'Energy Charge for Purchases" will be renamed the "Supply Charge"; and the "Amortization Charge" will be renamed the "Supply Adjustment Charge."

13 Adjust the current charges in the PPAC as follows: 1) decrease in the existing Amortization Charge (which is being renamed the Supply Adjustment Charge) from $0.02246/kWh to $0.01729/kWh; 2) increase in the Power System Delivery Charge (which is being renamed the Transmission Charge) from approximately $0.0138/kWh, on average, to approximately $0.0330/kWh on average (transmission charges vary by customer class); and 3) decrease in the Energy Charge for Purchases (which is being renamed the Supply Charge) from approximately $0.0865/kWh, on average, to $0.0725/kWh, on average (supply charges vary by customer class).

14 TOU in this decision means Time of Use.

(Section 5.9 of this decision). Once 2013 base rates have been so determined, rates for 2014, 2015 and 2016 shall be developed as follows:

1. The additional revenue requirements for 2014, 2015 and 2016, as compared to the 2013 revenue requirement will be achieved through an adjustment to the energy rates for each customer class. For customer classes with multiple tiers, the energy rate shall be added to each tier;
2. The 2014 energy adjustment is equal to the change in 2014 base rate revenue requirements ($400,000) divided by the 2014 approved sales forecast (144,694,448 kWh) or $0.002764. Similar adjustments to the 2015 and 2016 energy rate charges would be made.
3. BVES is authorized to file a Tier 1 AL to implement the adjustments to energy rates for 2014, 2015 and 2016.

4.12. Changes to Terms and Conditions

For purposes of implementing the Base Revenue Requirement Balancing Account (BRRBA), BVES recommended that the seasonal monthly allocation method be used, whereas ORA recommended that one-twelfth of the annual amount be used as the monthly portion of the annual revenue requirement in the BRRBA.

The Parties to the First Settlement agree that, for the duration of this rate cycle and for purposes of implementing the BRRBA, BVES may use agreed-upon monthly target values.[15]

4.12.1. Next Rate Case Application Filed Prior to January 31, 2016.

The Parties to the First Settlement agree that: a) BVES shall file its next general rate case application with a 2017 TY, prior to January 31, 2016; b) the cost

[15] Sales in megawatts hours (MWh) by month, for January through December: 10.77%, 9.39%, 8.75%, 7.65%, 7.27%, 7.12%, 7.51%, 7.57%, 7.21%, 7.28%, 8.53%, 10.95%, respectively.

allocation and rate design components of the application shall be filed by March 1, 2016; c) the application shall include a four-year rate cycle; and d) BVES may modify these filing dates for good cause through the appropriate procedural vehicle.

4.12.2. No Requirement for Updated Results of Operations Model

ORA requested that BVES upgrade its Results of Operations (RO) model to encompass all components of the RO in one file instead of six separate files, to which BVES responded that no upgrade in its RO model was necessary. The Parties to the First Settlement agree that BVES is not required to upgrade its RO Model to encompass all components of the RO into one file.

4.12.3. Calculation of Administrative Costs

ORA recommended that BVES calculate administrative costs on a total basis showing both the expense and capital portions in its next GRC, including an administrative cost capital survey that analyzes the amount of administrative costs that are capitalized. BVES responded that ORA's recommendations were unnecessary because BVES's overhead ratios are based on ratios developed by GSWC to allocate a portion of the capitalized Administrative and General costs to capital projects.

The First Settlement provides that BVES's administrative costs shall continue to be consistent with the Commission's determination of GSWC administrative costs as determined in GSWC's GRC.

4.12.4. Tax Memorandum Account

ORA requested that the Commission order BVES to address the disposition of amounts in the Tax Memorandum account by separate application, while BVES responded that it would address disposition of this account in its next GRC filing. The Parties to the First Settlement agree that BVES will address the Tax Memorandum Account in BVES's next GRC application.

4.12.5. No Adjustment to Accumulated Depreciation Reserve Account

ORA claimed that BVES's January 1, 2013 depreciation reserve account balance was understated and the depreciation reserve balance should be adjusted upward. BVES stated that ORA's recommendation was contrary to Commission ratemaking policy and GAAP.

The Parties to the First Settlement agree that no adjustment to BVES's depreciation reserve account shall be made in this proceeding. Neither ORA nor BVES concede their respective positions on this issue.

4.12.6. Except as Otherwise Provided in Settlement, Issues in BVES Application are Deemed Adopted in Settlement

The Parties to the First Settlement agree that all proposals or requests set forth in BVES's A.12-02-013 (except those withdrawn) are deemed adopted and accepted except as otherwise provided in the First Settlement.

4.12.7. Disposition of General Rate Case Memorandum Account

In D.12-08-006,[16] BVES was authorized to record interim rates based on BVES's 2012 authorized revenue requirement in order to track the change in revenue requirement adopted in this proceeding during the period between January 1, 2013 and the effective date of a final decision.[17]

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[16] On August 2, 2012, the Commission issued D.12-08-006, which authorized GSWC/BVES to establish a GRC Revenue Requirement Memorandum Account (GRC Memo Account).

[17] Interest is authorized to accrue on the balance beginning January 1, 2013, based on the Board of Governors of the Federal Reserve's three-month commercial paper rate.

The Parties to the First Settlement agree that the disposition of the GRC Memorandum Account (GRC Memo Account) shall be implemented through the use of BVES's existing BRRBA. For the disposition of 2013 amounts in the GRC Memo Account, BVES shall:

1) follow its existing BRRBA process through the filing of a Tier 1 AL to request recovery over two years, of any shortfall plus applicable interest; and
2) determine the shortfall by deducting its actual 2013 collections of $17,412,180 from the agreed-upon 2013 revenue requirement of $19,700,000, which results in a 2013 revenue shortfall in the BRRBA of $2,289,912.

For disposition of 2014 amounts in the GRC Memo Account, BVES shall determine any shortfall by deducting its actual 2014 collections recorded into the GRC Memo Account from the agreed-upon 2014 revenue requirement in the First Settlement of $20,100,000 (if approved) and request recovery. After such recovery of 2014 amounts, if a decision has been issued in this proceeding, the GRC Memo account shall be closed.

5. Discussion and Conclusion Regarding the First Settlement

Except for one clarification regarding disposition of the GRC Memo Account for 2014, the Commission finds that the First Settlement complies with Commission requirement for approval of settlements, because it is reasonable in light of the whole record, consistent with the law, and in the public interest.

Because this decision may be issued prior to the end of 2014, BVES may not have collected 12 months of interim rates in 2014. If that is the case, this partial year balance in the GRC Memo Account should more appropriately be offset by a fraction of the agreed-upon 2014 revenue requirement, based on the number of months for which interim rates were collected, instead of the full year amount. For example, if BVES collects interim rates for eight months in 2014, it should offset the balance in the GRC Memo Account for 2014 by eight-twelfths (8/12) of the agreed-upon revenue requirement for 2014 of $20,100,000.

With this clarification, the Commission shall adopt the First Settlement.

5.1. The First Settlement is Reasonable in Light of the Whole Record

This proceeding includes a full record of both written and oral testimony, ratepayer input at the PPHs, as well as briefs from the parties. The First Settlement was reached after careful analysis of the issues by each party involved, all of whom are knowledgeable and experienced, and includes detailed instructions regarding implementation of the terms of the First Settlement.

The First Settlement is consistent with Commission decisions on settlements, which express the strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record. This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results. Thus, we conclude the First Settlement is reasonable.

5.2. The First Settlement is Consistent With the Law

The terms of the First Settlement complies with all applicable statutes. These include Pub. Util. Code § 451 which in part requires, that utility rates must be just and reasonable, and Pub. Util. Code § 454, which in part prevent a change in public utility rates unless the Commission finds such an increase justified. Nothing in the First Settlement contravenes statute or prior Commission decisions.

5.3. The First Settlement is in the Public Interest

The First Settlement is in the public interest and in the interest of parties involved. The agreed-upon revenue requirement and its piece parts, pursuant to the First Settlement resolve all items at issue in this proceeding, except for those addressed in the Second Settlement.

Approval of the First Settlement avoids the cost of further litigation, and reduces the use of valuable resources of the Commission and the parties. The parties to the First Settlement comprise all of the active parties in this proceeding. Thus, the First Settlement commands the unanimous sponsorship of the affected parties who fairly represent the interests affected by the First Settlement. For example: 1) the agreed-upon base rate revenues for the 2013 TY are $1,394,100 less than BVES's 2012 base rate revenues; 2) the two large capital addition projects will not be recovered in rates until a particular phase is completed or the project is completed; and 3) a number of poles on Big Bear Boulevard that currently do not comply with the safety factor requirements of General Order 95 will be replaced.

We also find that the evidentiary record contains sufficient information for us to determine the reasonableness of the First Settlement and for us to discharge any future regulatory obligations with respect to this matter. For all these reasons, we approve the First Settlement.

6. Second Settlement Agreement

Pursuant to Rules 11.2 and 12.1(a),[18] GSWC/BVES, Snow Summit, and the City/BBARWA,[19] filed a motion on May 12, 2014 requesting approval and

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[18] Pursuant to Rule 12.1, parties to a proceeding may file a written motion requesting adoption of a settlement, anytime after the first PHC and within 30 days after the last day of hearing.

Footnote continued on next page

adoption of the Second Settlement. The issues addressed in the Second Settlement are limited to cost allocation issues and rate design principles for residential customers.

In accordance with Rule 12.1(b), the Parties to the Second Settlement convened a settlement conference on May 6, 2014. Notice and opportunity to participate were provided to all parties for the purpose of discussing a settlement in this proceeding. In their May 12, 2014 motion, the Parties to the Second Settlement state that the Second Settlement is reasonable, consistent with law, and in the public interest in accordance with Rule 12.1(d).

6.1. Cost Allocation

BVES recommended[20] allocating revenues to customer classes using a two-part allocation approach: 7.5% based on equal percentage of marginal cost (EPMC) and 92.5% based on system average percentage change (SAPC). BVES's goals of this proposal were to: 1) keep the rate increase for permanent residential customers below 11%; and 2) begin movement toward marginal cost-based revenue allocation, as ordered by the Commission in BVES's last GRC decision (D.09-10-028). Snow Summit recommended a revenue allocation based on 50% use of EPMC and 50% use of SAPC, which would be phased in two steps; 25% use of EPMC initially and then an additional 25% use of EPMC timed with

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Rule 11.6 permits motions for extensions of time to comply with the Rules or an ALJ ruling. Prior to filing the Joint Motion in the current proceeding (which was filed more than 30 days after the last day of hearing), counsel for GSWC/BVES submitted a motion through e-mail to the assigned ALJ, requesting an extension of time to file a motion for approval of a settlement agreement in this proceeding. The assigned ALJ granted GSWC/BVES's by an e-mail ruling on May 5, 2014, to May 12, 2014.

[19] Referred to throughout this decision as *Parties to the Second Settlement*.

[20] Reference Rebuttal Testimony.

the expected removal of the Supply Adjustment Charge surcharge (which BVES estimated would occur in September 2014). Snow Summit believes its proposal would have also balanced the goals of movement toward marginal cost-based revenue allocation. ORA recommended allocating revenues based on 3.33% use of EPMC and 96.7% use of SAPC.

The Parties to the Second Settlement agree to a revenue allocation for this proceeding based on 20% use of EPMC and 80% use of SAPC. Assuming the 2013 base rate revenue requirement agreed to in the First Settlement of $19,700,000, and assuming the forecasts of BVES sales, customer counts by revenue class and rate class, supply rate revenues, and miscellaneous revenues at present rates as agreed to in the First Settlement, the Parties to the Second Settlement agree to the following allocation of the $1,164,124 2013 revenue requirement increase (pursuant to the First Settlement).

This increase results in an average increase in revenues of 2.88% (which is equal to the Net Proposed [System Average Rates] SAR Change). The allocated increase in net revenues of $1,123,339 to residential customers uses an overall allocation of additional costs based on a 20% movement to EPMC-based revenue allocation. The total residential revenue allocation of $1,123,339 is divided between seasonal residential customers and non-seasonal residential customers in a manner that yields an equal percentage increase in revenues from both permanent and seasonal residential customer classes. The following table provides a breakdown of the allocation between customer classes:

Customer Class	Change in Net Revenues for Each Customer Class	Resulting Revenue Increase for Each Customer Class
Residential Permanent	$533,143	4.93%
Residential Seasonal	$590,196	4.93%
Residential Total	**$1,123,339**	4.**93**%
A-1	$101,813	2.05%
A-2	$54,777	1.63%
A-3	($62,202)	-1.53%
A4-Time of Use	($13,465)	-0.56%
Total Commercial	**$80,924**	**0.55%**
A5-Secondary	$15,950	9.47%
A5-Primary	($61,672)	-2.39%
Total Large Power	**($45,722)**	**-1.66%**
Streetlights	$5,583	4.75%
Total or Average	**$1,164,124**	**2.88%**

The Joint Parties to the Second Settlement comment that: 1) ORA has recommended a 3.33% EPMC based on what it identified as the particular circumstances of Bear Valley's service area (which consists primarily of "weekend" or vacation homes and the largest customer is a ski resort), and Commission decisions and policy; and 2) ORA posits that even with its recommendation, full time residential customers (with a median income of $33,000)[21] would see a rate increase of 9.47%.

21 According to the Mayor Pro Tem of the City of Big Bear, who spoke at the PPH, stating that the median household income is $33,000 (PPH August 13, 2012 at 12-13).

6.2. Rate Design Principles for Residential Customers

In its Application, BVES proposed rate designs for the residential customer class. These rate design proposals, combined with a 7.5% movement towards EPMC, would have resulted in a 10.97% increase in permanent residential customer rates and an 8.45% increase in seasonal residential customer rates.[22] The City expressed concern for the rates charged to its permanent residents, noting that many of its household incomes are well below the household incomes of numerous surrounding communities and the State of California as a whole.

In its Application, BVES proposed to replace the current $0.21 per meter per day service charge with a $0.33 per meter per day minimum charge. Such a rate design is similar to that which currently exists for seasonal residential rates, although it retains an energy rate tier structure to accommodate baseline allowances through an inverted tier structure using three levels. BVES proposed this change in order to address what it has identified as a disparity between bills for "extremely low" energy use (that is zero to 35 kWh/month use) versus bills for other low-use customers whose consumption is in the mid-range of the baseline tier through Tier 2. BVES believes that extremely low levels of consumption (under 35 kWh/month) are evidence that a household is not occupied on a permanent basis. BVES's rate design proposal for a $0.33 per day minimum charge addresses these extremely low-use bills by reducing the incentive for seasonal customers to falsely claim they are permanent residents. BVES also posits that unlike other electric utilities operating in California, its extremely small electric bills make up a significant percentage of total bills

[22] Exhibit BVES-23, Table 2 at 3.

rendered each month by BVES. BVES is concerned that this number may grow even larger if more seasonal residents claim they are permanent residents.[23] BVES believes this results in disproportionate subsidies by all other customers. BVES proposed to reduce the subsidy for customers using extremely small amounts of electricity in this GRC through the $0.33 per day minimum charge.

The Joint Parties to the Second Settlement state that: 1) ORA agrees that a minimum charge, as opposed to a service charge, should be implemented, but disagrees with the magnitude of the proposed minimum charge; 2) ORA proposes a $0.15 per meter per day minimum charge; and 3) ORA stated that BVES's proposal is not comparable to Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E). The Parties to the Second Settlement believe that ORA's proposal, which is less than the current $0.21/day minimum charge, exacerbates instead of solves the problem, because it reduces the current minimum charge. BVES believes that it, as a small mountain electric utility with a relatively high number of seasonal homes, is not comparable to PG&E or SDG&E in this circumstance. The Parties to the Second Settlement agree that it is reasonable to implement a minimum charge of $0.31 per meter day.

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[23] For example, in real dollar terms a 25 kWh bill decreased $1.25 or -13.6% and a 50 kWh bill decreased $0.70 per month or -6.8%. Over that same period, in real dollar terms a bill for 300 kWh (entirely within the current baseline allowance) increased by $4.81 or 23.8% and the bill for just slightly more than double baseline (700 kWh) increased by $32.75 or 113.3%. In real dollar terms, BVES states that the rate for a zero-use bill has decreased the most (-$1.80 or -22%). BVES also states that similar circumstances are not a serious problem for other utilities because the percentage of customers using 35 kWh or less of other utilities is a very small component of the total bills they render each month.

Currently, permanent residential Tier 2 rates are 30.5% above Tier 1 rates, and Tier 3 rates are 20.05% above Tier 2 rates. BVES had proposed to reduce the increases in Tiers 2 and 3, which it believes would provide rate stability while still providing an incentive to conserve. 56% of sales are in Tier 3, and Tiers 1 and 2 accounts for 44% of sales.[24] At these levels, BVES believed there was little incentive to conserve beyond the Tier 3 threshold. Also, BVES posits that since Tier 3 sales are the first to vary and also represent a majority of consumption, any fluctuation in sales has a pronounced impact on Tier 3 revenues. BVES stated that its proposal would reduce the disparity between tiers and result in greater stability in revenues collected from residential customers when sales fluctuate.

The Parties to the Second Settlement comment that ORA disagreed with revenue stability arguments, preferring to retain a high level of rate separation between Tiers 2 and 3, recommending a 25.9% rate increase in Tier 2 over Tier 1 and a 25.9% increase in Tier 3 over Tier 2. The Parties to the Second Settlement believe that ORA's proposal exacerbates the revenue volatility in Tier 3, and would put a greater burden on 56% of customer consumption for the benefit of the 44% minority. In reaching a compromise resolution, the Parties to the Second Settlement sought to achieve two primary objectives: reduce the Tier 3 revenue volatility and reduce bill impacts on residential customers with an average level of consumption of 450 kWh/month. To achieve these two objectives, the Parties to the Second Settlement agreed to increase the permanent residential Tier 2 rates by 30.6% above Tier 1 rates and permanent residential

[24] Exhibit BVES-26 at 5.

Tier 3 rates by 11.1% above Tier 2 rates. The Parties to the Second Settlement believe this compromise satisfies the goal of residential customer rate increases being simple, understandable, stable and publicly acceptable.

6.3. ORA Position Regarding Second Settlement Agreement

ORA contends that the Second Settlement is not reasonable, consistent with law, and in the public interest. ORA posits that the proposed cost allocation of 20% EPMC and 80% SAPC of the Second Settlement, which results in a 4.93% rate increase for Residential customers, is not a reasonable compromise between ORA's proposed 3.33% EPMC and Snow Summit's proposed 50% EPMC; and that the terms are not in accord with either EPMC or Systems Average Percentage (SAP). ORA also states that the Joint Parties misstate the reference to D.09-10-028 regarding movement towards marginal cost-based revenue allocation. In particular, ORA interprets D.09-10-028 to mean that the Commission adopted a Settlement Agreement that rejected the use of EPMC. ORA contends there is no "balance" or "equity" in a Second Settlement that includes a 4.93% increase for the total Residential customer class, and a 2.39% decrease for the A-5 Primary customer class. ORA continues to recommend a 3.33% EPMC that it contends would move rates in an equitable and balanced manner and would be consistent across customer categories.

ORA also rejects the proposed Residential Rate Design of the Second Settlement Agreement, in which the Joint Parties propose an increase of the existing minimum charge of $0.21/day to $0.33/day and increases to Tiers 1 and 2 rates. Regarding the proposed increase to the minimum charge ORA argues that: 1) BVES's assumption that the current minimum charge is an incentive for seasonal residents to claim they are permanent, is an unsubstantiated claim; 2) the 57% increase in the minimum charge on residential customers exceeds the 20% cap referenced in BVES's last GRC. ORA also continues to recommend that the Commission adopt a per-day charge of $0.15 in keeping with that of other utilities, such as PG&E and SDG&E.

ORA opposes the proposal in the Second Settlement to increase permanent residential rates by 30.6% for Tier 2 rates (over Tier 1) and 11.1% for Tier 3 rates (over Tier 2). ORA posits that: 1) this proposal would shift the rate increases on the middle and lowest levels of consumption, rather than the highest tier; 2) there is no record to justify proposed rate increases; and 3) one of the proposed increases exceeds the 20% rate shock cap the Commission described in its last BVES GRC decision.

7. Discussion and Conclusion Regarding the Second Settlement

The Commission finds that portions of the Second Settlement are reasonable in light of the whole record, consistent with the law, and in the public interest, as detailed below. The Commission does not adopt the portion of Second Settlement regarding revision to the service charge.

7.1. EPMC/SAPC

This proceeding includes a full record of both written and oral testimony, ratepayer input at the PPHs, as well as briefs from the parties. The Marginal Cost Allocation portion of the Second Settlement is in compliance with applicable Commission decisions and in the public interest. Even though ORA does not support the Second Settlement, the City represents all classes of ratepayers, including residential and commercial ratepayers. This portion of the Second Settlement Agreement avoids the cost of further litigation, and reduces the use of valuable resources of the Commission and the parties. We find that the evidentiary record contains sufficient information for us to determine the reasonableness of the Second Settlement Agreement and for us to discharge any future regulatory obligations with respect to this matter.

In D.09-l0-028,[25] the Commission discussed our guiding principles regarding the use of EPMC in cost allocation:

> While this Commission has made use of EPMC a primary goal, we have acknowledged that it is not always feasible to reach that goal in a single proceeding.[26] The Commission may determine that circumstances render it impractical or against the public interest to immediately transition to EPMC analysis, in which case EMPC should be implemented only as early as the circumstances permit. This Commission has identified rate impacts as an important concern when contemplating use of EPMC and determined that revenue allocations under the EPMC that result in increases above 20% for certain customers "[do] not represent a reasonable balancing of our ratemaking goals." (D.90-12-066; 1990 Cal. PUC LEXIS 1285, *32.) Thus, use of EPMC in ratemaking is a goal that must be balanced against other considerations.

The Commission finds that the Second Settlement's use of 20% EPMC complies with the requirements discussed above: 1) the 20% EPMC starts a gradual movement towards EPMC; 2) balances the interests of all classes of ratepayers; and 3) results in rate increases below 20%.

As detailed in D.09-10-028, the Commission may implement EPMC over a series of GRC's. With the use of 20% in the current proceeding, movement towards 100% EPMC has begun and may continue in future GRC's, based on considerations detailed in D.09-10-028.

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[25] D.09-10-028 at 6-7.

[26] *See* D.92-06-020; 1992 Cal. PUC LEXIS 472, *58.

D.09-10-028 and D.90-12-066 require the Commission to balance the interest of all customers groups, in light of: 1) the rate increase that results from use of EPMC; 2) comparison to historical allocation of rates and movement towards 100% EPMC; and 3) the change in total rates that moves BVES gradually towards 100% EPMC. All of these items must result in rates that are in the public interest.

As detailed in D.09-10-028, use of EPMC should not result in rate increases greater than 20%. The Joint Parties to the Second Settlement Agreement provided a table (*see* Section 7.1 above) which shows revenue increases resulting from a 20% EPMC ranging from -2.39% to 9.47%, with Residential ratepayers receiving a revenue increase of 4.93%. Because revenue increases for all the customer classes are under 20%, we find that the rate increase resulting from the use of a 20% EPMC is reasonable and in compliance with D.09-10-028.

Historically, BVES rates have resulted in Residential customers paying less than marginal cost, while Commercial and Large Power customers have paid more than their marginal cost. In order to resolve this inequity, begin to bring BVES's rates into equilibrium with EPMC, the allocation must be corrected for past over-and under-charging of customer classes. By moving towards EPMC, Residential rates must move up and other customer class rates must move down, in order to eventually reach 100% EPMC. We therefore find that the 20% EPMC brings all customer classes closer to each ones cost responsibilities, and provides a movement towards 100% EPMC that balances all customer classes' interests.

The Commission does not agree with ORA's issue that rate shock results for Residential customers through the use of a 20% EPMC. ORA posits that because Residential customers are responsible for 96.5% of the rate increase being allocated, they experience rate shock. The Commission finds that the

20% EPMC does not result in rate shock because the Residential customer class will only experience a 4.93% increase in revenue requirement. Furthermore, the Residential customer class has not been paying the marginal costs they are responsible for under SAP, while other customer classes have paid more than their share of marginal costs under SAP. As a result, moving towards 100% EPMC requires a rate increase for Residential customer classes and a rate decrease for other customer classes.

We therefore approve the Marginal Cost Allocation portion of the Second Settlement Agreement. We find that this portion of the Second Settlement balances interests of all customer classes and weighs the various requirements detailed in D.09-10-28 and other Commission decisions regarding use of EPMC.

7.2. Minimum Charge

The Minimum Charge portion of the Second Settlement is not in compliance with applicable Commission decisions and is not the public interest. Neither the Joint Parties to the Second Settlement's proposed minimum charge of $0.33/day nor ORA's recommendation of $0.15/day[27] is supported by the record.

We reject ORA's argument that the proposed increase in the minimum charge of 57%[28] is in violation of the 20% cap discussed in D.09-10-028.[29] This 20% cap is applicable to the EPMC, not a minimum charge. The Commission also finds that ORA's recommended reduction in the minimum charge to $0.15/day is not supported by the record. In its Exhibit ORA-13, ORA states that its proposal is closer to the rates charged by PG&E and SDG&E of $4.44/month

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27 Exhibit DRA-13 at 9.

28 (($0.33 - $0.21)/$0.33).

29 D.09-10-028 at 7.

and $5.10/month, respectively. ORA provides: 1) no calculation in support of why $0.15/day (equates to $4.50/month); and 2) no support for why BVES's minimum charge should be less than those of PG&E or SDG&E. With no calculation in support of its $0.15/day, the Commission cannot determine its reasonableness, or whether some other figure is more appropriate. With no details as to why BVES should have a similar minimum charge to PG&E or SDG&E, the Commission cannot weigh the reasons to determine if the other utilities' minimum charges are applicable.

We also reject the Joint Parties to the Second Settlement's proposal of increasing the minimum charge to $0.33. The Commission accepts BVES's and the Joint Parties argument that the minimum surcharge is used to collect fixed costs from very low permanent users, and that the number of these types of customers (low-use) has been increasing since 2002.[30] But, as with ORA's recommendation, neither BVES nor the Joint Parties provided a calculation in support of the proposed increase to $0.33. Without that information, the Commission is unable to assess if the increase to $0.33/day would resolve BVES's concerns regarding low use customers. Also, without documentation of what the Joint Parties refer to as an advertisement by mail box businesses that seasonal customer could use a mail box to claim permanent residential rates status, the Commission is unable to determine the reliability of this footnote.

Because no one provided sufficient support for their proposal, the Commission orders that the service charge currently in existence for BVES,

[30] Exhibit BVES 6 at 32.

which is set at a rate of $0.21/day, shall remain in place until the next GRC, when parties may revisit this issue.

7.3. Tiered Rates

The Tiered Rates portion of the Second Settlement is not in compliance with applicable Commission decisions and is not the public interest.

The Tiered Rates portion of the Second Settlement posits that increasing Tier 2 rates (30.6%) more than Tier 3 rates (11.1%), rates which will stabilize and Tier 3 would no longer subsidize Tiers 1 and 2. In support of this, the Joint Parties to the Second Settlement state that: 1) the disparity in rates between Tier 3 and Tiers 1 and 2 discourages conservation; 2) customers that pay Tier 3 rates subsidize those that pay Tiers 1 and 2 rates, as revenues generated from Tier 3 rates make up 56% of such revenues collected while revenues generated from Tiers 1 and 2 make up 44%; and 3) because Tier 3 revenues make up a greater percentage, any variability in these sales would have a greater impact on revenues.

ORA opposes putting more of the increase on Tier 2 customers, recommending instead to raise rates at the same percentage increase, so that Tier 1 and 2 customers do not pay for a greater percentage of the increase than Tier 3 customers. ORA supported this recommendation, stating that what it identified as a more than 37% rate increase to the rates for Tier 1 and Tier 2 exceeded the 20% rate shock cap in D.09-10-028 at 7.

Pursuant to Pub. Util. Code §739,[31] tiered rates are broken out by a percent of average usage within that particular utility. Baseline, or Tier 1 usage, is

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[31] Public Utilities Code Section 739(a)(1) "Baseline quantity" means a quantity of electricity or gas allocated by the commission for residential customers based on from 50 to 60 percent of

Footnote continued on next page

calculated by taking 60% of average consumption. With that starting point, Tier 2 is calculated by taking 130% of the calculated Tier 1 usage, and Tier 3 is calculated by determining what exceeds 130% of Tier 1 usage.[32] In their Joint Reply Comments to ORA's comments to the Second Settlement, the Joint Parties state that average permanent residential consumption is 450 kWh/month. By using the average usage figure of 450 kWh/month, Tier 1 usage should be 270 kWh/month,[33] Tier 2 usage should be 351 kWh/month,[34] and Tier 3 should be usage over 351 kWh/month. We also note that the Second Settlement includes Tier 1 and Tier 2 usages of 316 kWh/month and 410 kWh/month, respectively (which result from an average usage figure of 526.7 kWh/month).[35] These are very different from those reached using the 450 kWh/month figure.

Until this discrepancy regarding the average usage is clarified, the tiered rates themselves should not be changed. We also note that Tier 3 rates are supposed to receive price signals that discourage usage and encourage conservation; and since average usage has declined from 526.7 kWh/month to

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average residential consumption of these commodities, except that, for residential gas customers and for all-electric residential customers, the baseline quantity shall be established at from 60 to 70 percent of average residential consumption during the winter heating season. In establishing the baseline quantities, the commission shall take into account climatic and seasonal variations in consumption and the availability of gas service. The commission shall review and revise baseline quantities as average consumption patterns change in order to maintain these ratios.

[32] R.12-10-06-013 PG&E Settlement at 2-3: Section g. The terms "Tier 1," Tier 2", Tier 3" and "Tier 4," as used herein, are defined as follows: Tier 1: usage up to 100% of baseline; Tier 2: usage between 100% up to 130% of baseline; Tier 3: usage between 130% up to 200% of baseline; Tier 4: usage above 200% of baseline.

[33] 450 kWh/month times 60% = 270 kWh/month.

[34] 270 kWh/month times 130% = 351 kWh/month.

[35] 316 kWh/month divided by 60% = 527.6 kWh/month.

450 kWh/month, conservation appears to be working at all tiers. And, even if the Commission had determined that a rate change was appropriate, neither the Second Settlement nor ORA provided supporting calculations for their proposed changes to the tiered rate changes, leaving nothing for the Commission to verify the rates to. Also, ORA's use of the 20% cap is not applicable to tiered rates, and only applies to EPMC.

The Commission therefore rejects both the tiered rate proposal in the Second Settlement and that of ORA. With no alternatives to these proposals, we order that the tiered rate percentage differential remain the same as currently authorized, applied to the revenue requirement agreed to in the First Settlement Agreement and adopted herein (*see* Appendices C and D herein). The following table illustrates the adopted Residential Rate Design Principles and Rates.

RATE	COMPONENT	CURRENT		SETTLEMENT		ADOPTED	
		Values	% Change in Tiers	Values	% Change in Tiers	Values	% Change in Tiers
D*	Minimum charge per day (currently called service charge)	$0.2100		$0.33		**$0.2100**	
	Tier 1 - Base line 315 kWh ($/kWh)	$0.0621		$0.08556		**$0.08353**	
	Tier 2 - 30% over baseline ($/kWh)	$0.0810	30.5%	$0.11176	30.6%	**$0.10900**	30.5%
	Tier 3 - all use above 2 ($/kWh)	$0.0973	20.1%	$0.12414	11.1%	**$0.13091**	20.1%
DMS	Multi-family sub metered			Increase discount from $0.044/day to $0.10/day. **		**Increase discount from $0.044/day to $0.10/day. ****	

RATE	COMPONENT	CURRENT		SETTLEMENT		ADOPTED	
DO	Minimum charge per day	$0.85		$0.85		**$0.85**	
	Base Energy ($/kWh)	$0.1427		$0.17240		**$0.17240**	
	Service Charge ($/day)	$0.21		$0.21		**$0.21**	

Minimum Charges: There are no changes in current tariff language except permanent residential. A minimum charge applied to the calculation of the total bill will be assessed when the sum of the standard energy, transmission, and supply charges is less than the specified Minimum Charge. This change eliminates surcharges in the minimum bill calculation.

*All other D-related rates including DM, DMS, and DE are a function of the D rate.

**The increase in the DMS discount reduces the bill impact on this customer group from the increase in the minimum charge.

8. Advice Letter

Unless discussed separately herein: 1) BVES shall file a Tier 1 AL within 30 days of the issuance of this decision in order to make all preliminary statements, rate and tariff changes authorized herein for 2013 and 2014; 2) BVES shall file a Tier 1 AL by December 1, 2014 in order to make all preliminary statements, rate and tariff changes authorized herein for 2015; and 3) BVES shall file a Tier 1 AL by December 1, 2015 in order to make all preliminary statements, rate and tariff changes authorized herein for 2016.

9. Comments on the Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311 and comments were allowed under Rule 14.3. Opening comments regarding the First Settlement were jointly filed on September 22, 2014 by GSWC/BVES, ORA, and Snow Summit. Opening comments regarding the Second Settlement were jointly filed by GSWC/BVES and Snow Summit on September 22, 2014, and separately by ORA on September 22, 2014. Reply Comments were filed on September 29, 2014, jointly by GSWC/BVES and Snow Summit, and individually by ORA. The issues raised in these comments have been discussed in the text above as necessary.

10. Assignment of Proceeding

Catherine J.K. Sandoval is the assigned Commissioner and Seaneen M. Wilson is the assigned ALJ in this proceeding.

Findings of Fact

1. On February 16, 2012, GSWC, on behalf of its BVES, filed A.12-02-013 to increase rates charged for electric service within its service territory by 9.85%, which results in a proposed rate increase of 7.79%.

2. On April 5, 2012, GSWC/BVES filed its Amended Application.

3. BVES is a wholly-owned subsidiary of ASWC, which is operated through another ASWC subsidiary, GSWC. BVES provides retail electric service to the Big Bear Lake resort area in the San Bernardino Mountains. The BVES service territory is a resort community, comprised primarily of residential customers. BVES provides service to approximately 23,300 customers, of which 21,900 are residential customers and approximately 1,400 are commercial, industrial, or public authority customers. BVES also provides service to two ski resorts in its territory. The BVES system is comprised of one 8.4 MW generation plant, 205 miles of overhead and 54 miles of underground conductors, and 13 substations. BVES's generation plant, the BVPP, began commercial operation in 2005 and is located at BVES's main office in Big Bear Lake. BVES's distribution facilities are located within the control area operated by the CAISO, but are not directly interconnected with the CAISO-controlled high-voltage transmission grid. The BVES distribution system connects to the CAISO grid through transmission and distribution facilities owned, controlled, and operated by SCE.

4. On March 8, 2012, Resolution ALJ-176-3290 preliminarily determined that this proceeding was ratesetting and that hearings would be necessary.

5. Protests were filed by Snow Summit on March 21, 2012, ORA on March 23, 2012, and individually by BBARWA and the City on April 18, 2012. These protests were filed in response to GSWC/BVES's Application and Amended Application. GSWC/BVES filed responses to these protests on April 2, 2012 and April 20, 2012.

6. On April 17, 2012, the PHC took place in San Francisco to establish the service list for the proceeding, discuss the scope of the proceeding, and develop a procedural timetable for the management of the proceeding. Besides GSWC/BVES, parties to this proceeding include Snow Summit, ORA, BBARWA, and the City.

7. On April 26, 2012, GSWC/BVES filed a motion requesting authority to open a GRC Memorandum Account. ORA responded this motion on May 11, 2012, and GSWC/BVES replied to the response on May 16, 2012. On August 2, 2012, the Commission issued D.12-08-006, in which it authorized GSWC/BVES to establish a GRC Memorandum Account.

8. On May 14, 2012, the assigned Commissioner issued her Scoping Memo, which addressed the scope and schedule for this proceeding.

9. Two PPHs were held in Big Bear Lake on August 27, 2012. The primary concern of the customers that spoke was the level of GSWC/BVES's requested rate increase.

10. On September 17-19, 2012, EHs were held. GSWC/BVES, ORA, and BBARWA/City presented witnesses in support of their respective testimonies.

11. On November 9, 2012, GSWC/BVES filed a motion requesting the reopening of the record, to which ORA and BBARWA/City replied on

November 30, 2012. GSWC/BVES replied on December 7, 2012. ORA and BBARWA/City took no position as to whether the record should be reopened or not. On December 14, 2012, the assigned ALJ issued an e-mail ruling, in which she granted GSWC/BVES's motion to reopen the record, and also set a date, January 3, 2013, for a second PHC. GSWC/BVES and BBARWA/City each issued PHC statements on December 28, 2012. SCE requested party status in order to participate in this proceeding, based on its interest in the issue for which GSWC/BVES requested reopening of the record. The assigned ALJ granted SCE party status.

12. On January 7, 2013, the assigned Commissioner issued her Amended Scoping Memo, in which she addressed the limited scope and schedule for the second phase of this proceeding. The scope of this phase was limited to review and assessment of new information regarding GSWC/BVES's proposed undergrounding of poles on Big Bear Boulevard.

13. An EH in the second phase of this proceeding was held on October 30, 2013. New information was included in GSWC/BVES's rebuttal testimony regarding contributions by other entities such as Verizon to the costs associated with poles on Big Bear Boulevard.

14. In order to provide parties with an opportunity to respond, the assigned ALJ informed parties at the EH, that they could file and serve opening and reply comments on this issue only. GSWC/BVES and ORA filed and served opening and reply comments on November 20 and 27, 2013, respectively.

15. Opening briefs addressing issues in both phases were filed on December 13, 2013 by GSWC/BVES, ORA, SCE, Snow Summit, and BBARWA/City. Reply briefs addressing issues in both phases were filed on

December 23, 2013 by GSWC/BVES, ORA, SCE, Snow Summit, and BBARWA/City.

16. The Joint Comparison Exhibits filed jointly on December 16, 2013 by GSWC/BVES, ORA, BBARWA/City, and Snow Summit provide a comparison of TY 2013 results of operations to show the differences between GSWC/BVES and ORA.

17. On April 24, 2014, GSWC/BVES noticed a settlement conference for April 25, 2014 which would address all outstanding issues in the current proceeding except cost allocation and residential rate design.

18. On April 28, 2014, GSWC/BVES noticed a settlement conference for May 6, 2014 which would address the issues of cost allocation and residential rate design.

19. On May 2, 2014, GSWC/BVES requested (through e-mail) an extension to file settlements, by May 12, 2014. This request was granted through an e-mail ruling by the assigned ALJ on May 5, 2014.

20. On May 12, 2014, two motions were filed – one requesting adoption of a settlement regarding all outstanding issues in the current proceeding except cost allocation and residential rate design (First Settlement Agreement), and another requesting adoption of a settlement regarding cost allocation and residential rate design (Second Settlement Agreement).

21. ORA filed comments against the Second Settlement Agreement on June 6, 2014.

22. The Parties to the Second Settlement filed a reply to ORA's comments on June 20, 2014.

23. The Parties to the First Settlement Agreement include all parties except SCE. SCE has authorized BVES to state that it will not oppose the Commission's approval of the settlement.

24. The parties are fairly reflective of the affected interests.

25. No term of the First Settlement Agreement contravenes statutory provisions or prior Commission decisions.

26. The First Settlement Agreement conveys to the Commission sufficient information to permit it to discharge its future regulatory obligations with respect to the parties and their interests.

27. The First Settlement Agreement is reasonable in light of the record, is consistent with law, and is in the public interest.

28. The revenue requirement as set forth in the First Settlement Agreement is reasonable.

29. The Parties to the Second Settlement Agreement include GSWC/BVES, Snow Summit, and City/BBARWA.

30. Selected terms of the Second Settlement Agreement: 1) contravene statutory provisions or prior Commission decisions; 2) do not provide sufficient information to permit the Commission to discharge its future regulatory obligations with respect to the parties and their interests; 3) are not reasonable in light of the record; 4) are not consistent with law; and 5) are not in the public interest.

31. The Parties to the Second Settlement agree to a Marginal Cost Allocation for this proceeding based on 20% use of EPMC and 80% use of SAPC. Assuming the 2013 base rate revenue requirement agreed to in the First Settlement of $19,700,000, and assuming the forecasts of BVES sales, customer counts by revenue class and rate class, supply rate revenues, and miscellaneous revenues at

present rates as agreed to in the First Settlement, the Parties to the Second Settlement agree to an average increase in revenue requirement of $1,164,124 in 2013, or 2.88%. The breakdown of the allocation of the revenue increase between customer classes ranges from a low of -1.53% for A-3 Commercial to a high of 9.57% for A5-Secondary Large Commercial. Residential rates would increase by 4.93%.

32. The Marginal Cost Allocation portion of the Second Settlement is in compliance with applicable Commission decisions and in the public interest.

33. The Parties to the Second Settlement agree that it is reasonable to implement a minimum charge of $0.33 per meter day, to address what they identify as a concern that some low-use seasonal residential users are falsely claiming they are permanent residents.

34. The Parties to the Second Settlement agreed to increase the permanent residential Tier 2 rates by 30.6% and permanent residential Tier 3 rates by 11.1%, in order to address what they identify as disparity between Tiers 1 and 2 compared to Tier 3, which would result in greater stability in revenues collected from residential customers when sales fluctuate.

35. ORA contends that the cost allocation in the Second Settlement of 20% EPMC8 and 80% SAPC: 1) is not a reasonable compromise between ORA's proposed 3.33% EPMC and Snow Summit's proposed 50% EPMC; and 2) that the Joint Parties misstate the referenced D.09-10-028 regarding movement towards marginal cost based revenue allocation.

36. ORA rejects the proposed Residential Rate Design of the Second Settlement Agreement, arguing that: 1) BVES's assumption that the current minimum charge is an incentive for seasonal residents to claim they are permanent, is an unsubstantiated claim; 2) the 57% increase in the minimum

charge on residential customers exceeds the 20% cap referenced in BVES's last GRC as being beyond a "reasonable balance of ratemaking goals; and 3) the Commission should adopt a per-day charge of $0.15 in keeping with that of other utilities, such as PG&E and SDG&E.

37. ORA opposes the proposal in the Second Settlement to increase permanent residential rates by 30.6% for Tier 2 rates (over Tier 1) and 11.1% for Tier 3 rates (over Tier 2), because it posits that: 1) this proposal would shift the rate increases on the middle and lowest levels of consumption, rather than the highest tier; 2) there is no record to justify proposed rate increases; and 3) one of the proposed increases exceeds the 20% rate shock cap the Commission described in its last BVES GRC decision.

38. The City represents all classes of ratepayers, including residential and commercial ratepayers.

39. The Marginal Cost Allocation portion of the Second Settlement Agreement avoids the cost of further litigation, and reduces the use of valuable resources of the Commission and the parties.

40. In D.09-10-028, the Commission discussed our guiding principles regarding the use of EPMC in cost allocation.

41. While this Commission has made use of EPMC a primary goal, we have acknowledged that it is not always feasible to reach that goal in a single proceeding.[36] The Commission may determine that circumstances render it impractical or against the public interest to immediately transition to EPMC analysis, in which case EMPC should be implemented only as early as the

[36] *See* D.92-06-020; 1992 Cal. PUC LEXIS 472, *58.

circumstances permit. This Commission has identified rate impacts as an important concern when contemplating use of EPMC and determined that revenue allocations under the EPMC that result in increases above 20% for certain customers "[do] not represent a reasonable balancing of our ratemaking goals." (D.90-12-066; 1990 Cal. PUC LEXIS 1285, *32.) Thus, use of EPMC in ratemaking is a goal that must be balanced against other considerations.

42. The Marginal Cost Allocation portion of the Second Settlement's use of 20% EPMC complies with the requirements discussed in D.09-10-028: 1) the 20% EPMC starts a gradual movement towards EPMC; 2) balances the interests of all classes of ratepayers; and 3) results in rate increases below 20%.

43. As detailed in D.09-10-028, the Commission may implement EPMC over a series of GRCs. With the use of 20% in the current proceeding, movement towards 100% EPMC has begun and may continue in future GRCs, based on considerations detailed in D.09-10-028.

44. D.09-10-028 and D.90-12-066 require the Commission to balance the interest of all customers groups, in light of: 1) the rate increase that results from use of EPMC; 2) a comparison to historical allocation of rates and movement towards 100% EPMC; and 3) the change in total rates that moves BVES gradually towards 100% EPMC. All of these items must result in rates that are in the public interest.

45. As detailed in D.09-10-028, use of EPMC should not result in rate increases greater than 20%. Because the individual customer revenue increases are all under 20%, we find that the rate increase resulting from the use of a 20% EPMC is reasonable and in compliance with D.09-10-028.

46. Historically, BVES rates have resulted in Residential customers paying less than marginal cost, while Commercial and Large Power customers have paid more than their marginal cost.

47. Under SAP, Residential ratepayers have been responsible for 56.6% of the allocation, while under 100% EPMC they are actually responsible for 63.5% of marginal costs. Other customer classes such as Commercial and Large Power have been paying more than their share of EPMC under SAP.

48. In order to resolve this inequity, the Commission begins to bring BVES's rates into equilibrium with EPMC, which corrects for past over-and under-charging of customer classes.

49. By moving towards EPMC, Residential rates must move up and other customer class rates must move down, in order to eventually reach 100% EPMC.

50. Neither the Parties to the Second Settlement's proposed minimum charge of $0.33/day nor ORA's recommendation of $0.15/day is supported by the record or any calculations.

51. With no supporting calculations, the Commission is unable to assess the reasonableness of either proposal.

52. Because the 20% cap discussed in D.09-10-028 is applicable to the EPMC and not a minimum charge or tiered rates, we do not apply it in our review of the Minimum Charge or the Tiered Rate sections of the Second Settlement.

53. There is no support on the record for why BVES's minimum charge should be less than those of PG&E or SDG&E, therefore is not considered in our review of the Minimum Charge section of the Second Settlement.

54. The Commission accepts BVES's and the Parties to the Second Settlement's argument that the minimum surcharge is used to collect fixed costs from very

low permanent users, and that the number of these types of customers (low-use) has been increasing since 2002.

55. No documentation was provided by the Parties to the Second Settlement that an advertisement by mail box business entice seasonal customers to use a mail box to claim permanent resident rates status, the Commission is unable to determine the reliability of this footnote.

56. The current Minimum Surcharge for BVES is $0.21/day.

57. Pursuant to Pub. Util. Code § 739, tiered rates are broken out by a percent of average usage within that particular utility.

58. Baseline, or Tier 1 usage, is calculated by taking 60% of average consumption.

59. With that starting point, Tier 2 is calculated by taking 130% of the calculated Tier 1 usage, and Tier 3 is calculated by determining what exceeds 130% of Tier 1 usage.

60. In their Joint Reply Comments to ORA's comments to the Second Settlement, the Parties to the Second Settlement state that average permanent residential consumption is 450 kWh/month, Tier 1 usage is 316 kWh/month, and Tier 2 usage is 410 kWh/month.

61. By using the average usage figure of 450 kWh/month, Tier 1 usage should be 270 kWh/month (450 kWh/month times 60% = 270 kWh/month), Tier 2 usage should be 351 kWh/month (270 kWh/month times 130% = 351 kWh/month), and Tier 3 should be usage over 351 kWh/month.

62. The Second Settlement includes Tier 1 and Tier 2 usages of 316 kWh/month and 410 kWh/month, respectively, which result from an average usage figure of 526.7 kWh/month (316 kWh/month divided by 60% = 527.6

kWh/month). These are very different from those reached using the 450 kWh/month figure.

63. Until the discrepancy regarding the average usage is clarified, the tiered rates themselves cannot be changed.

64. Tier 3 rates are supposed to receive price signals that discourage usage and encourage conservation; and since average usage has declined from 526.7 kWh/month to 450 kWh/month, then conservation appears to be working at all tiers.

65. Neither the Parties to the Second Settlement nor ORA provided supporting calculations for their proposed changes to the tiered rate changes.

Conclusions of Law

1. The rates authorized for BVES in this GRC allow BVES to meet its obligations pursuant to Public Utilities Code Section 451, to take all actions "...necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

2. The First Settlement Agreement is reasonable in light of the whole record, consistent with law, in the public interest and should be approved.

3. The disposition of the GRC Memo Account should be implemented through the use of BVES's existing BRRBA. For the disposition of 2013 amounts in the GRC Memo Account, BVES should:

a. Follow its existing BRRBA process through the filing of a Tier 1 AL to request recovery over two years, of any shortfall plus applicable interest; and

b. Determine the shortfall by deducting its actual 2013 collections of $17,412,180 from the agreed-upon 2013 revenue requirement of $19,700,000, which results in a 2013 revenue shortfall in the BRRBA of $2,289,912.

4. For the disposition of 2014 amounts in the GRC Memo Account, BVES should:

a. Follow its existing BRRBA process through the filing of a Tier 1 AL to request recovery of any shortfall plus applicable interest;

b. Because this decision is being issued prior to the end of 2014, BVES should not have collected 12 months of interim rates (pursuant to D.12-08-006). That being the case, this partial year balance in the GRC Memo Account should be offset by a fraction of the agreed upon 2014 revenue requirement, based on the number of months for which interim rates were collected, instead of the full year amount; and

c. After such recovery of 2014 amounts, once a decision has been issued in this proceeding, the GRC Memo account should be closed.

5. Selected sections of the Second Settlement Agreement, including the Minimum Charge and Tiered Rates issues, are not reasonable in light of the whole record, consistent with law, in the public interest and should not be approved.

6. The Marginal Cost Allocation portion of the Second Settlement should be adopted. This Marginal Cost Allocation balances interests of all customer classes and weighs the various requirements detailed in D.09-10-28 and other Commission decisions regarding use of EPMC.

7. Because no one provided sufficient support for their proposal, the Commission should order that the service charge currently in existence for BVES, which is set at a rate of $0.21/day, shall remain in place until the next GRC, when parties may revisit this issue.

8. The Commission should order that the tiered rate percentage differential remain the same as currently authorized and be applied to the revenue increase agreed to in the First Settlement.

9. Preliminary statements, Base Rates and Total Rates for BVES, shown in Appendices A, C and D, respectively, of this decision, should be adopted.

10. Unless discussed separately herein: 1) BVES should file a Tier 1 AL within 30 days of the issuance of this decision in order to make all preliminary statement, rate and tariff changes authorized herein for 2013 and 2014; 2) BVES should file a Tier 1 AL by December 1, 2014 in order to make all preliminary statements, rate and tariff changes authorized herein for 2015; and 3) BVES should file a Tier 1 AL by December 1, 2015 in order to make all preliminary statements, rate and tariff changes authorized herein for 2016.

11. To implement the update of the General Office expense allocation, BVES should file a Tier 1 AL within 90 days of the date of the decision in a GSWC GRC case that adjusts general office costs allocated to BVES.

12. Within 90 days of the completion and placement into commercial operation of the Moon Ridge Substation Upgrade Project, or any of the authorized phases of the Big Bear Boulevard Underground Project, BVES should file a Tier 1 AL requesting implementation of proposed new base rates for as much as the agreed-upon costs for each project plus accrued AFUDC at an annual rate of 6.69%.

O R D E R

IT IS ORDERED that:

1. The Uncontested Settlement Agreement filed by Golden State Water Company on behalf of its Bear Valley Electric Service Division, the Office of Ratepayer Advocates, the City of Big Bear Lake and Big Bear Area Regional Wastewater Agency, and Snow Summit, Inc., which is attached in Appendix A to this decision, is reasonable in light of the whole record, consistent with law, in the public interest and is approved.

2. The disposition of the General Rate Case Memorandum Account (GRC Memo Account) shall be implemented through the use of Bear Valley Electric Service Division's (BVES) existing Base Revenue Requirement Balancing Account (BRRBA). For the disposition of 2013 amounts in the GRC Memo Account, BVES shall:

   a. Follow its existing BRRBA process through the filing of a Tier 1 Advice Letter to request recovery over two years, of any shortfall plus applicable interest; and

   b. Determine the shortfall by deducting its actual 2013 collections of $17,412,180 from the agreed-upon 2013 revenue requirement of $19,700,000, which results in a 2013 revenue shortfall in the BRRBA of $2,289,912.

3. For the disposition of 2014 amounts in the General Rate Case Memorandum Account (GRC Memo Account), Bear Valley Electric Service Division (BVES) shall:

   a. Follow its existing Base Revenue Requirement Balancing Account process through the filing of a Tier 1 Advice Letter to request recovery of any shortfall plus applicable interest;

b. Because this decision is issued prior to the end of 2014, BVES will not have collected 12 months of interim rates (pursuant to Decision 12-08-006). That being the case, this partial year balance in the GRC Memo Account shall be offset by a fraction of the agreed upon 2014 revenue requirement, based on the number of months for which interim rates were collected, instead of the full year amount; and

c. After such recovery of 2014 amounts, and once a decision has been issued in this proceeding, the GRC Memo account shall be closed.

4. The Marginal Cost Allocation portion of the Cost Allocation and Residential Customer Rate Design Settlement Agreement filed by Golden State Water Company on behalf of its Bear Valley Electric Service Division, the City of Big Bear Lake and Big Bear Area Regional Wastewater Agency, and Snow Summit, Inc., which is attached in Appendix B to this decision, is adopted.

5. The Minimum Charge portion and the Tiered Rates portion of the Cost Allocation and Residential Customer Rate Design Settlement Agreement found in Appendix B is rejected.

6. Bear Valley Electric Service Division's Minimum Charge shall remain at the current rate of $0.21/day.

7. Bear Valley Electric Service Division's tiered rate percentage differentials shall remain the same as currently authorized and be applied to the revenue increase agreed to in the Uncontested Settlement Agreement, attached as Appendix A of this decision.

8. Preliminary statements, Base Rates and Total Rates for Bear Valley Electric Service Division, shown in Appendices A, C and D, respectively, of this decision, are adopted.

9. Application 12-02-013 is closed.

This order is effective today.

Dated November 6, 2014, at Bakersfield, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

Appendix A

Settlement Agreement Addressing All Outstanding Issues Except Cost Allocation and Rate Design

Exhibit B

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Golden State Water Company, on behalf of its Bear Valley Electric Service Division (U 913 E), for Approval of Costs and Authority to Increase General Rates and Other Charges for Electric Service by its Bear Valley Electric Service Division	Application No. 12-02-013 (Filed February 16, 2012)

UNCONTESTED SETTLEMENT AGREEMENT

1. INTRODUCTION

1.1. In accordance with Rule 12.1(a) of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure ("Rules"), the Settling Parties (as defined in section 2 below) enter into this settlement agreement ("Settlement") for purposes of resolving certain matters in this proceeding, as specifically described herein.

1.2. The attached Uncontested Joint Motion for Commission Approval and Adoption of Settlement Agreement ("Settlement Approval Motion") sets forth the factual and legal bases of the Settlement; advises the Commission of its scope; and presents the grounds on which Commission approval and adoption are urged.

1.3. As the Settlement Approval Motion explains, the Settlement complies with Commission requirements for approval of settlements because it is reasonable in light of the whole record, consistent with the law, and in the public interest. Accordingly, the Settling Parties respectfully urge the Commission to adopt and approve this Settlement.

1.4. The Settling Parties are entering into this Settlement to avoid the uncertainty of a Commission decision that could produce results undesirable to the Settling Parties, and to expedite Commission approval of provisions and tariffs consistent with this Settlement.

1.5. Since this Settlement represents a compromise by them, the Settling Parties have entered into each component of this Settlement on the basis that its approval by the Commission not be construed as an admission or concession by any Settling Party regarding any fact or matter of law in dispute in this proceeding or in any other proceeding before the Commission. Furthermore, the Settling Parties intend that the approval of this Settlement by the Commission not be construed as a precedent or statement of policy of any kind for or against any Settling Party in any current or future proceeding.

1.6. All issues among and between the Settling Parties have been resolved through this Settlement except:

1.6.1. Cost allocation among customer classes (*i.e.*, how to allocate the overall revenue requirement among customer classes); and

1.6.2. Rate design principles for residential customers. The Settling Parties have agreed, however, to rate design principles for all non-residential rate classes. Rates to recover the base rate revenue requirement cannot be determined with the information included in this Settlement. Once the Commission has determined the cost allocation between customer classes and residential rate design principles (combined with the issues resolved in this Settlement), base rates can be determined.

1.7. The GRC application in this proceeding was for Test Year 2013. Much of the record in this proceeding is in terms of the 2013 revenue requirement. Most of the figures cited in this Settlement are expressed in terms of 2013 costs and revenue requirements.

1.8. The Settling Parties anticipate that the Commission will issue a final decision in this proceeding prior to December 31, 2014. The Settling Parties agree that new 2014 rates should go into effect the date the Commission issues a final decision granting the Settlement Approval Motion and approving the Settlement.

2. DEFINITIONS

2.1. The term "BVES" means Bear Valley Electric Service (U 913-E), a division of Golden State Water Company, the applicant in this proceeding.

2.2. The term "ORA" means the Office of Ratepayer Advocates[37].

2.3. The term "Snow Summit" means Snow Summit, Inc.

2.4. The term "City" means the City of Big Bear Lake, California.

2.5. The term "BBARWA" means the Big Bear Area Regional Wastewater Agency.

2.6. The term "Settling Parties" means collectively BVES, ORA, Snow Summit, the City, and BBARWA.

3. ATTACHMENTS

3.1. The following documents are attached to, and made a part of, this Settlement Agreement.

3.1.1. Exhibit A: Base Revenue Requirement Balancing Account.

3.1.2. Exhibit B: Pension Balancing Account.

3.1.3. Exhibit C: Energy Efficiency Balancing Account.

3.1.4. Exhibit D: Solar Initiative Balancing Account.

3.1.5. Exhibit E: Solar Initiative Program.

3.1.6. Exhibit F: Public Purpose Program Adjustment Mechanism.

3.1.7. Exhibit G: 2013 Settlement Supply Rates.

3.1.8. Exhibit H: Supply Adjustment Mechanism.

3.1.9. Exhibit I: Schedule SSC – Special Service Charges.

3.1.10. Exhibit J: Rule 9.

3.1.11. Exhibit K: Schedule No. "S" Standby.

3.1.12. Exhibit L: Rule 7.

3.1.13. Exhibit M: Rule 20.

3.2. Upon approval of this Settlement, BVES is authorized to implement each of the above-referenced attachments through a Tier 1 AL filing.

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37 The Division of Ratepayer Advocates was renamed the Office of Ratepayer Advocates effective September 26, 2013. Although during the bulk of this proceeding references were made to the Division of Ratepayer Advocates or "DRA", for purposes of this Settlement, all references shall be to the Office of Ratepayer Advocates or "ORA."

4. TERMS AND CONDITIONS REGARDING BASE RATE REVENUE REQUIREMENTS

Except as otherwise noted, the litigation amounts or positions of a Party set forth below are consistent with those reflected in the Joint Comparison Exhibit accepted into the record in this proceeding as Exhibit JC-1, and attached as Appendix A to the Joint Motion.

4.1. ***2013 Base Rate Revenue Requirement.*** BVES requested a Test Year 2013 base rate revenue requirement of $22,096,378[38] as compared to ORA's recommendation of $18,147,968. The Settling Parties agree to an overall base rate revenue requirement for Test Year 2013 of $19,700,000, as set forth in the table below.

	BVES	ORA	Settlement
2013 Base Rate Revenue Requirement	$22,095,378	$18,147,968	$19,700,000

The Settling Parties focused on a settlement of an overall revenue requirement.[39] The parties did not negotiate a final settlement value for every component of the base rate revenue requirement, however they did negotiate values and provisions for certain components. Thus the Settlement does not have specific values for many components of revenue requirements, such as operating expenses, taxes, rate base, and net income. The Settling Parties did specifically agree upon the components of the overall revenue requirement set forth below:

- A composite depreciation rate of 2.3%.
- A capital additions budget of $2.5 million in 2013 and 2014 and $3.0 million in 2015 and 2016 (excluding the two Major Plant Additions, as discussed below).
- An authorized ROE of 9.95% and an ROR of 8.60% (discussed below).
- Allocated BVES Costs from GSWC's GRC (discussed below).

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[38] The BVES values used in comparisons between ORA and Settlement are based on the BVES rebuttal testimony.

[39] BVES has the flexibility to adjust its expenses from the proposed levels in its application in order to achieve the proposed TY 2013 base rate revenue requirement level.

The following table summarizes the key components of BVES 2013 revenues:

BVES Revenues by Component
2013 in Millions

Component	BVES	ORA	Settlement
Total Present Rate Revenue	$40.69	$40.69	$40.69
Total Revenues Other Than Base Rate Rev	$22.29	$22.29	$22.29
Present Total Base Rate Revenues (excl Base Adj Revenue)	$18.40	$18.40	$18.40
Shortfall In Base Revenue To Authorized GO Allocation	$1.64	$1.64	$1.64
Shortfall in Base Revenue Due to Reduced Sales Forecast From Settlement	$1.05	$1.05	$1.05
2012 Authorized Base Revenue Requirement	$21.09	$21.09	$21.09
Proposed Increase to Reach 2013 Base Revenue Requirement	$1.00	($2.95)	($1.39)
Proposed 2013 Base Revenue Requirement	$22.10	$18.15	$19.70
Total Proposed Base Revenue Increase	$3.70	($0.25)	$1.30
Total Proposed Rate Revenue (incl OOR, Base Adj & Surcharges)	$44.39	$40.44	$41.99
Overall NET Revenue Increase	**9.09%**	**(0.62%)**	**3.20%**

System Average Rate Change Test Year 2013

Electric Revenue & Rate Components	BVES		ORA		Settlement	
	Revenues	SAR $kWh	Revenues	SAR $kWh	Revenues	SAR $kWh
Total Electric Base Rate Revenue	$19,772,663	$0.141836	$19,772,663	$0.141836	$19,772,663	$0.141836
Total Supply Rate Revenue	$17,297,600	$0.124082	$17,297,600	$0.124082	$17,297,600	$0.124082
Surcharge Revenue	$3,696,989	$0.026520	$3,387,538	$0.024300	$3,387,538	$0.024300
Total Electric Sales Revenue & SAR	**$40,457,801**	**$0.290218**	**$40,457,801**	**$0.290218**	**$40,457,801**	**$0.290218**
Increase In Revenue	**$3,696,989**	**$0.026520**	**($224,714)**	**($0.001612)**	**$1,301,611**	**$0.009337**
Offset from Standby & Other Operating Income Increase	($137,488)	($0.000986)	($137,488)	($0.000986)	($137,488)	($0.000986)
Net Proposed SAR Change	$3,559,501	$0.025534	($362,202)	($0.002598)	$1,164,124	$0.008351
Proposed Rate SAR	**$44,017,302**	**$0.315752**	**$40,095,599**	**$0.287620**	**$41,621,925**	**$0.298569**
Increase to the Average Electric Rate	**8.80%**		**(0.90)%**		**2.88%**	

4.2. ***Post Test-Year Mechanism (PTAM).*** BVES offered several different post test-year mechanisms ("PTAM") proposals for 2014, 2015 and 2016. The BVES proposals included indices to escalate operation and maintenance expenses and administrative and general expenses, a Z factor for other taxes, and recognition of capital additions based on a forecast of plant additions plus carrying charges. Under a BVES simplified PTAM alternative, BVES offered increases in the Test Year 2013 revenue requirements of approximately $1.883 million, $1.289 million and $1.229 million for 2014, 2015 and 2016, respectively. (Exhibit BVES-2, p. 43, Table 4.3). ORA proposed a PTAM mechanism based upon the Urban Price Index for 2014, 2015 and 2016, with an offsetting productivity factor of 0.5%, which would have resulted in approximate increases of $341,180, $356,840 and $364,240 for 2014, 2015 and 2016, respectively. Snow Summit supported ORA's proposal regarding PTAM. Both BVES and ORA PTAM proposals were tied to index values. The Settling Parties agree to a PTAM that fixes the revenue requirement increase of $400,000 for each of the years 2014, 2015, and 2016, as set forth in the table below.

PTAM Increase Over 2013 Revenue Requirement	BVES	ORA	Settlement
2014	$1,883,000	$341,180	$400,000
2015	$1,289,000	$356,840	$400,000
2016	$1,229,000	$364,240	$400,000

4.3. ***Overall Base Rate Revenue Requirement***. In light of the Settling Parties' agreement on Test Year 2013 base rate revenue requirements and PTAM adjustments for 2014, 2015, and 2016, the overall base rate revenue requirements for BVES' rate cycle agreed to by the Settling Parties are set forth in the table below.

Settlement	2013	2014	2015	2016
Base Rate Revenue Requirements	$19,700,000	$20,100,000	$20,500,000	$20,900,000

4.4. ***Authorized ROE of 9.95% and ROR of 8.60%.*** The Settling Parties agree that the base rate revenue requirement of $19.7 million in 2013 implicitly includes an adopted return on equity ("ROE") of 9.95% and a corresponding rate of return ("ROR") on ratebase of

8.60%. BVES had requested an ROE of 11.71% and an ROR of 9.57%, while ORA requested an ROE of 9.35% and an ROR of 8.27%, and Snow Summit requested an ROE of 8.39% with no recommendation on ROR, all as set forth in the table below.

	BVES	ORA	Snow Summit	Settlement
Debt Ratio	45%	45%	No position	45%
Equity Ratio	55%	55%	No position	55%
Cost of Debt	6.96%	6.96%	6.94%	6.96%
Cost of Equity	11.71%	9.35%	8.39%	9.95%
Rate of Return on Return on Rate Base	9.57%	8.27%	No position	8.60%

4.5. ***Ongoing Authority to Use GO Allocation Update for Certain Costs.*** BVES requested authority to adjust revenue requirements through an advice letter process whenever the Commission authorizes a different allocation to BVES for general office ("GO") costs, common plant allocations, or pension and benefits. ORA did not oppose the request to update GO costs and recommended that common plant costs be updated along with GO allocations. ORA opposed updating the pension and benefit costs through the GO allocation process. The Settling Parties agree that BVES may, on an ongoing basis, use the existing GO allocation process to update the following allocation of GSWC costs to BVES: (i) GSWC GO costs; (ii) GSWC common plant costs; and (iii) GSWC pension and benefit costs (collectively, the "Allocated BVES Costs"), each as approved by the Commission in a GSWC GRC decision. The tables below summarize the values for each of the Allocated BVES Costs based on Commission Decision 13-05-011 in GSWC's most recent GRC Application 11-07-017.

GSWC Allocation to BVES: General Office and Common Plant

Item	2013	2014	2015
General Office	$3,320,100	$3,392,000	$3,470,400
Common Plant	$4,898,046	$4,798,182	$4,698,182

GSWC Allocation to BVES: Pension and Benefit Costs

Item	2013	2014	2015
Pensions (Amount for Pension Balancing Account)*	**$536,900**	**$536,900**	**$536,900**
All other Benefits:			
Medical	$472,900	$512,000	$554,200
Dental	$46,900	$49,500	$52,200

Vision	$6,600	$6,700	$6,800
Life Insurance	$7,163	$7,306	$7,452
EAP	$940	$959	$978
401-K Contribution	$142,600	$145,500	$148,700
Defined Contribution Plan	$14,100	$20,000	$26,100
SERP	$3,895	$4,001	$4,059
VEBA	$56,900	$56,900	$32,300
Management Bonuses	$30,400	$30,858	$31,528
Stock options, AKA Restricted Stock.	$66,522	$67,523	$68,989
Total: All "other" Benefits	**$848,921**	**$901,247**	**$933,306**

* The BVES Pension Balancing Account, which only includes pension costs, starts with the 2013 value of $536,900 and tracks this value to actual until a new pension cost is established as a result of a Commission decision in a GSWC GRC proceeding.

The base rate revenue requirements agreed to by the Settling Parties did not include specific values for many of the components of the base rate revenue requirements; however, the Settling Parties agree that the base rate revenue requirements set forth in Section 4.3 above implicitly include the Allocated BVES Costs set forth in the tables immediately above.

The Settling Parties further agree that when the Commission issues a decision in a subsequent GSWC GRC case that adjusts Allocated BVES Costs (upward or downward), BVES shall make corresponding adjustments to the revenue requirements in the Base Revenue Requirement Balancing Account ("BRRBA") Preliminary Statement.

For illustrative purposes only, the Settling Parties provide the following example. Assume that in the next GSWC GRC, the Commission approves the following amounts of Allocated BVES Costs for calendar year 2016: pension costs -- $486,900, other benefits costs -- $1,033,306, GO costs -- $3,598,400, and common plant costs -- $4,798,182. BVES would then determine the difference between the Commission-approved 2016 Allocated BVES Costs and the Commission-approved 2015 Allocated BVES Costs, and make the appropriate adjustment to the 2016 revenue requirement in the BRRBA. The table below demonstrates how the 2016 revenue requirement in the BRRBA would be updated to reflect new Commission-approved Allocated BVES Costs using costs assumed in this example.

Example of a Change in BRRBA Revenue Requirement
with New GSWC Cost Allocation to BVES

GSWC Costs Allocated to BVES	2015 Allocation	2016 Allocation	Change from 2015	Revenue Requirement Change
GO	$3,498,400	$3,598,400	$100,000	$100,000
Pension	$536,900	$486,900	$(50,000)	$(50,000)
Other Benefits	$933,306	$1,033,306	$100,000	$100,000
Total Allocated expenses	**$4,968,606**	**$5,118,606**	**$150,000**	**$150,000**
Common plant	$4,698,182	$4,798,182	$100,000	$19,200 *
Total Revenue Requirement Change				**$169,200**

*Assumes a 19.2% carrying charge.

Based upon the example table above, the revenue requirement for 2016 of $20,900,000 agreed to by the Settling Parties and set forth in the BRRBA would be increased by $169,200 resulting in a new BRRBA revenue requirement in 2016 of $21,069,200. This change would be effectuated through a Tier 1 advice letter filing. Similar adjustments would be made for the BRRBA revenue requirements in subsequent years based upon Commission-approved Allocated BVES Costs.

4.6. ***Pension Balancing Account.*** BVES proposed a pension and benefit balancing account that would also include medical costs. ORA opposed the request and recommended either no balancing account or a one-way balancing account. Alternatively, ORA proposed a cost-sharing balancing account mechanism between ratepayers and shareholders for expenses above the annual amounts authorized by the Commission. The Settling Parties agree to BVES establishing a Pension Balancing Account ("PBA") under the same terms and conditions as authorized by the Commission in D. 13-05-011 for GSWC's pension and benefit balancing account. The new PBA to be added to the Preliminary Statement is attached hereto as Exhibit B. The Settling Parties agree that BVES shall not establish a balancing account for medical expenses or other non-pension benefit costs during this rate cycle. The PBA shall track actual BVES pension costs against the pension costs of $536,900 allocated to BVES in the most recent GSWC GRC Decision 13-05-011. BVES shall update the BVES pension cost allocation amount in the PBA whenever the Commission adopts a new BVES pension cost allocation in a GSWC GRC.

For illustrative purposes only, the Settling Parties provide the following example. Assume that in the next GSWC GRC, the Commission approves a BVES pension cost allocation for calendar year 2016 in the amount of $486,900. For calendar 2016, BVES would then modify the PBA to track actual 2016 BVES pension costs against the pension cost allocation amount of $486,900.

4.7. ***Confirmation of Sales and Other Revenue Forecasts.*** The Settling Parties confirm the forecasts regarding BVES Sales, Customers and Other Operating Revenues as summarized in Exhibit BVES-1 Tables 4B, 4C, 4D, and 4L and set forth below.

Table 4B
2011 to 2016 Forecasted Sales by Revenue Class (kWh)

RATE CLASS	2011	2012	2013	2014	2015	2016
Residential	75,055,533	76,106,563	77,847,297	79,701,630	81,019,851	81,874,526
Commercial	44,021,458	45,389,468	48,335,524	51,693,766	53,543,857	54,285,642
Power	12,940,496	12,960,791	13,030,184	13,107,200	13,132,901	13,127,384
Street Lighting	191,852	191,852	191,852	191,852	191,852	191,852
Total	**132,209,339**	**134,648,674**	**139,404,857**	**144,694,448**	**147,888,461**	**149,479,404**

Table 4C
2010 - 2016 Customer Count by Revenue Class, Full-Time Equivalent

Component	2010 Recorded	2011 Estimated	2012 Estimated	2013 Estimated	2014 Estimated	2015 Estimated	2016 Estimated
Residential	21,349	21,503	21,635	21,762	21,890	22,019	22,151
Commercial	1,321	1,349	1,368	1,388	1,408	1,428	1,447
Power	4	4	4	4	4	4	4
Street Lighting	4	4	4	4	4	4	4
Total	**22,678**	**22,860**	**23,011**	**23,158**	**23,306**	**23,455**	**23,606**

Table 4D
2010 – 2016 Sales by Rate Class (KWh)

Rate Class	2010 Recorded	2011 Estimated	2012 Estimated	2013 Estimated	2014 Estimated	2015 Estimated	2016 Estimated
D (Sgl Fam Res "SFR")	31,094,251	29,894,938	30,216,708	30,855,891	31,567,734	32,008,028	32,196,417
DE (Employees SFRs)	297,204	288,524	297,392	310,241	322,085	332,551	340,535
NEM (Net Energy)	96,754	85,484	85,484	85,484	85,484	85,484	85,484
D-All Electric (SFRs)	69,769	147,618	150,114	144,318	151,056	142,784	142,133
D (Life Support SFRs)	791,471	1,583,883	1,727,451	1,884,733	2,048,551	2,214,442	2,381,966
DLI (Low Income SFRs)	11,838,491	11,351,937	11,444,373	11,420,008	11,350,566	11,412,105	11,538,900
DM (Master Metered)	180,411	167,610	173,202	170,496	171,430	167,477	163,742
DMS (Submetered)	2,184,058	2,184,089	2,249,509	2,323,376	2,399,569	2,467,275	2,528,960
Perm Residential	**46,552,409**	**45,704,083**	**46,344,233**	**47,194,547**	**48,096,475**	**48,830,146**	**49,378,137**
Seasonal DO	29,586,663	29,351,450	29,762,330	30,652,750	31,605,155	32,189,705	32,496,389
Res Subtotal	**76,139,072**	**75,055,533**	**76,106,563**	**77,847,297**	**79,701,630**	**81,019,851**	**81,874,526**
A-1 Small (up to 20KW)	16,803,998	15,741,785	15,688,727	16,500,677	17,565,006	17,756,602	17,315,724
A-2 Medium (20-50KW)	10,233,005	10,148,320	10,693,519	11,582,105	12,566,747	13,233,076	13,663,504
A-3 Large (50-500KW)	12,269,003	11,151,470	11,736,233	12,452,538	13,192,720	13,863,791	14,448,042
A-4 TOU	5,100,050	6,844,653	7,135,759	7,664,974	8,234,063	8,555,158	8,723,142
Camp Oaks	137,185	135,230	135,230	135,230	135,230	135,230	135,230
Commercial	**44,543,241**	**44,021,458**	**45,389,468**	**48,335,524**	**51,693,766**	**53,543,857**	**54,285,642**
A-5 TOU sec	31,906	730,706	730,706	730,706	730,706	730,706	730,706
A5-TOU prim	11,297,884	12,209,790	12,230,085	12,299,478	12,376,494	12,402,195	12,396,678
Power	**11,329,790**	**12,940,496**	**12,960,791**	**13,030,184**	**13,107,200**	**13,132,901**	**13,127,384**
Street Ltg	**191,852**	**191,852**	**191,852**	**191,852**	**191,852**	**191,852**	**191,852**
TOTAL	**132,203,955**	**132,209,339**	**134,648,674**	**139,404,857**	**144,694,448**	**147,888,461**	**149,479,404**

Table 4L
Miscellaneous Revenue at Present Rates 2011 to 2016

Category	2011	2012	2013	2014	2015	2016
Service Establishment	$39,705	$40,842	$41,978	$43,115	$44,251	$45,388
Reconnect Fees	$32,791	$34,292	$35,794	$37,295	$38,797	$40,298
Collection/Notice Fees	$56,824	$56,824	$56,824	$56,824	$56,824	$56,824
Temp Serve & Clean/Show	$3,901	$3,992	$4,083	$4,174	$4,264	$4,355
Return Check Fee	$0	$0	$0	$0	$0	$0
Late Payment Fee	$0	$0	$0	$0	$0	$0
Other Miscellaneous	$150	$150	$150	$150	$150	$150
Joint Pole	$95,629	$95,629	$95,629	$95,629	$95,629	$95,629
TOTAL	**$229,000**	**$231,729**	**$234,458**	**$237,186**	**$239,915**	**$242,644**

4.8. ***Confirmation of Certain Rate-Related Values***. The Settling Parties confirm that the Net-to-Gross Factor value is 1.80472%, the Franchise Fee value is 0.899%, and the Uncollectibles value is 0.433%.

5. PROJECTS/COSTS NOT FUNDED BY BASE RATE REVENUE REQUIREMENTS AGREED TO BY SETTLING PARTIES.

BVES requested approval for $5.1 million to recover the costs of replacing the existing overhead lines along Big Bear Boulevard with underground wires. The proposed project was included in BVES' capital budget request, and was projected to be completed over a three-year period (2013, 2014, and 2015). BVES recommended approval in base rates for 2013 a portion of the costs of the Big Bear Boulevard Underground Project and the Office Expansion Project. BVES also recommended the costs of the Moon Ridge Substation Upgrade and North Shore 34 KV Reconductor Project be included in base rates for 2015. BVES' proposed PTAM method would have recognized recovery of the post-2013 costs for all four of these major plant addition projects. ORA and the City opposed the Big Bear Boulevard Undergrounding Project and ORA opposed the Office Expansion Project. ORA's recommendation for the 2015 capital projects was by FERC account only rather than by project name, which precludes a direct comparison between ORA and BVES. However, implicit in ORA's recommendation of $2,223,013 for 2015 capital projects versus BVES recommendation of $6,711,383 is that ORA's recommended funding level would not have provided sufficient funding for the Moonridge Substation Upgrade Project or the North Shore 34 KV Reconductor Project.

During settlement negotiations, BVES undertook a more detailed investigation and analysis of, among other things, the condition and type of underground equipment existing along Big Bear Boulevard, and revised its estimated cost of the Big Bear Boulevard Undergrounding Project to be $7,732,081.

BVES agrees to withdraw its request for the Office Expansion Project and the North Shore 34 KV Reconductor Project, and the Settling Parties agree that BVES may construct and/or implement the projects and programs listed below, subject to the cost parameters set forth below. Except as specifically provided below, these projects and programs will not be funded by the base rate revenue amounts agreed-upon by the Settling Parties as set forth in Section 4.3 above. The source and amount of funding for the following projects and programs are as described below.

5.1. ***Two Major Plant Additions.*** In addition to any capital additions BVES determines to undertake and fund with the base rate revenues agreed to in Section 4.3 above, the Settling Parties agree that BVES may construct two major capital additions projects as listed below. Upon completion and placement into commercial operation of a project (or a phase of the Big Bear Boulevard Undergrounding Project), BVES may file a Tier 1 advice letter filing requesting implementation of proposed new base rates (rather than a surcharge) to recover the costs of a project (or phase of a project). Furthermore, the BRRBA authorized revenue requirement will be updated to include the effect of the increased authorized base revenue requirements. In no event shall cost recovery using a Tier 1 advice letter filing exceed the amount for a project, as set forth below, plus accrued allowance for funds used during construction ("AFUDC") at an annual rate of 6.96% for the period prior to receiving rate recovery. Subject to the review of (i) the accuracy and appropriateness of costs for a project (or phase of a project, as the case may be) being sought for recovery, (ii) the authorized cost of a project to be recovered using a Tier 1 advice letter filing, and (iii) the appropriateness of the requested base rates to recover such costs, the proposed base rates contained in a Tier 1 advice letter shall go into effect 30 days from the date it is filed. If a project's costs exceed the amount authorized to be recovered using a Tier 1 advice letter filing as set forth below, BVES may use a portion of its capital additions budget authorized in Section 4.1 of this Settlement to cover the remaining costs in order to complete the project.

5.1.1. Big Bear Boulevard Undergrounding Project: The authorized costs for recovery using a Tier 1 advice letter filing with respect to this Project is $7,032,540, plus AFUDC. BVES has the discretion to establish up to five phases of this Project for purposes of Tier 1 advice letter rate recovery. BVES may seek recovery through a Tier 1 advice letter filing of any amount of cost for any phase of the Project that is completed and placed into commercial operation, provided that the aggregate costs sought for recovery using a Tier 1 advice letter filing for all phases of the Project do not exceed $7,032,540, plus applicable AFUDC. In light of BVES' current estimate that the Project may cost $7,732,081, the actual Project costs may exceed the $7,032,540, plus applicable AFUDC; and limits using the Tier 1 advice letter process for costs above the $7,032,540, plus AFUDC. If actual costs for the Project exceed $7,032,540, plus applicable AFUDC, BVES may use a portion of its capital additions budget authorized in Section 4.1 of this Settlement to cover the remaining costs in order to complete the Project.

5.1.2. Moon Ridge Substation Project: The authorized costs for recovery of this Project using a Tier 1 advice letter filing is $1,461,667, plus applicable AFUDC. A Tier 1 advice letter filing may be made upon completion and placement of the Project into commercial operation. If the Project's costs exceed $1,461,667, plus applicable AFUDC, BVES may use a portion of its capital additions budget authorized in Section 4.1 of this Settlement to cover the remaining costs in order to complete the Project.

5.2. ***Energy Efficiency Program One-Way Balancing Account***. BVES requested an energy efficiency program ("EE Program") funding level of $230,000 a year in base rates. ORA recommended an EE Program funding level of $176,072 a year in base rates. The Settling Parties agree to an EE Program funding level of $200,000 per year, totaling $800,000 over the four-year rate case period. The Settling Parties further agreed to remove funding of the EE Program from base rate revenues. Funding for the EE Program will occur through the use of Public Purpose Program Surcharges. In order to implement this funding approach, BVES shall establish a one-way balancing account (the "Energy Efficiency Balancing Account" or "EEBA") as provided in Exhibit C attached hereto. The purpose of the EEBA is to track the costs of the Energy Efficiency Program and the revenues generated by the Public Purpose Program Surcharge to fund the Energy Efficiency Program. In Exhibit F attached hereto, the Preliminary Statement for the Public Purpose Program Adjustment Mechanism ("PPPAM") has been revised to reflect the addition of the Energy Efficiency Program as part of the PPPAM.[40] Program funding, within the limits prescribed below, may be allocated between residential and non-residential programs as determined by BVES. For the entire four-year rate cycle (2013-2016), a maximum of $800,000 is authorized for this Program. For each year of

[40] The revised PPPAM tariff provisions also update the calculation of Franchise Fees and Uncollectibles to include the values of 0.899% for Franchise Fees and 0.433% for Uncollectibles.

the four-year rate cycle, a target annual budget of $200,000 is established. For each of 2013, 2014, and 2015, any amount of costs above or below the target budgeted amount of $200,000 shall be carried over and deducted from or added to, as the case may be, the next year's target budgeted amount of $200,000. If there are any unspent amounts below the target budgeted amount of $200,000 (as adjusted) in the EEBA at the end of 2016, BVES shall account for such unspent amounts in a manner directed by the Commission in BVES' next GRC. If 2016 costs exceed the target budgeted amount of $200,000 (as adjusted), such costs shall not be subject to recovery by BVES from its ratepayers. In no event shall BVES recover in charges over the 2013-2016 time period more than the overall Program authorized amount of $800,000.

5.3. ***Solar Initiative Program One-Way Balancing Account.*** BVES requested a solar program with an overall budget of $1,462,500 in base rates, with a target capacity of 800 kW to be achieved in four steps over a period up to eight years. ORA recommended a two-step program with a target capacity of 335 kW for a four-year period and a total budget of $546,000 in base rates. The Settling Parties agree to the establishment of a solar initiative program ("SI Program") as described in Exhibit E attached hereto. Funding of the SI Program will not be from base rate revenues. Funding will occur through the use of Public Purpose Program Surcharges. In order to implement this funding approach, BVES shall establish a one-way balancing account (the "Solar Initiative Balancing Account" or "SIBA") for a new Solar Initiative Program. Exhibit D provides the SIBA Preliminary Statement which describes the SIBA. The purpose of the SIBA is to track the costs of the SI Program and the revenues generated by the Public Purpose Program Surcharge to fund the SI Program. In Exhibit F attached hereto, the Preliminary Statement for the PPPAM has been revised to reflect the addition of the SI Program as part of the PPPAM. The table below summarizes the Program budgets.

Steps	Incentive ($/watt)	Capacity (KW) Incentive	Budget Nominal	Admin	Total
1	$1.60	155	$248,000	$105,000	$353,000
2	$1.30	180	$234,000	$70,000	$304,000
3	$1.09	215	$234,350	$80,000	$314,350
4	$0.94	250	$235,000	$80,000	$315,000
Totals		**800**	**$951,350**	**$335,000**	**$1,286,350**
Annual Cost					**$160,794**

The Program objective is 800 KW installed in four Steps, implemented over a period of up to eight years. Although each of the Steps is expected to take two years to complete, a step may be less than or greater than two years depending upon customer demand. Annual Program expenditures are estimated to be $160,794 during the eight-year period of the Program. Step 1 budget includes an administrative cost of $105,000 to initially set up the Program and process applications. An incentive payment of $1.60 per installed kilowatt of solar capacity up to 155 KW is budgeted for Step 1, for a Step 1 total budgeted cost of $353,000. For Step 2, administrative costs to process applications will be $70,000 plus program incentive payments of $1.30 per installed kilowatt of solar capacity up to 180 KW for a Step 2 total budgeted cost of $304,000. For Step 3, administrative costs to process applications will be $80,000 plus program incentive payments of $1.09 per installed kilowatt of solar capacity up to 215 KW for a Step 3 total budgeted cost of $314,350. For Step 4, administrative costs to process applications will be $80,000 plus program incentive payments of $0.94 per installed kilowatt of solar capacity up to 250 KW for a Step 4 total budgeted cost of $315,000. For each of Step 1, Step 2 and Step 3, any amount of costs above or below the budgeted amount set forth above shall be carried over and deducted from or added to, as the case may be, the next Step's budgeted amount. Upon completion of Step 4 or 2020 (whichever comes first), if there are any unspent amounts below the budgeted amount (as adjusted) in the SIBA, BVES shall account for such unspent amounts in a manner directed by the Commission in BVES' Test Year 2021 GRC. In no event shall BVES recover more than the overall authorized Program cost of $1,286,350. BVES will include a summary of Program expenditures and achievements in BVES' 2017 GRC application.

6. CONFIRMATION OF POWER SUPPLY COSTS, CHARGES AND RATE DESIGN.

6.1. ***BVES Sought Confirmation of Amounts in PPAC Balancing Account.*** In BVES Exhibit-4, BVES submitted testimony regarding historical supply cost information in its "PPAC" balancing account. It also submitted requests for renaming certain charges and adjusting the rates of certain charges. ORA stated that it did not take issue with BVES' testimony in BVES Exhibit-4. Accordingly, the Settling Parties confirm BVES proposals set forth in BVES Exhibit-4. For ease of reference, certain of the more important supply cost information and proposals are set forth in this Settlement.

6.2. ***Confirmation of PPAC Account Balances.*** The Settling Parties confirm as follows. The PPAC account balance (under-collection, in this case) as of March 31, 2001 was $15,676,922 on an accrual basis. Excluding the required adjustments to energy costs due to the $77/MWh Cap, a total of $151,022,008 of costs were booked into the PPAC Balancing Account for the period April 1, 2001 through August 31, 2011, as summarized below:

8. 1. Long-term firm purchased power costs of $119,125,317.
9. 2. Purchases of short energy of $8,991,332 less revenue from the sale of surplus energy of $7,578,100 for a net cost of short-term energy of $1,413,232.
10. 3. SCE transmission costs of $15,302,522.
11. 4. CAISO costs of $10,442,590.
12. 5. Scheduling Coordinator costs of $922,625.
13. 6. Natural gas costs of $768,174, natural gas transportation costs of $324,424 and natural gas storage costs of $30,624.
14. 7. Resource adequacy costs of $1,930,000.
15. 8. Heat rate option costs of $762,500. (Exhibit BVES-4, p. 48, lines 6-18)

16. BVES properly reduced the amounts of energy costs in the PPAC by $3,348,292, resulting in total power costs booked into the PPAC Account of $147,673,735. (Exhibit BVES-4, p. 48, lines 20-21) BVES properly recovered in rates $147,673,735 of power costs booked into the PPAC Account from April 1, 2001 through August 31, 2011 (Exhibit BVES-4, p. 48, lines 21-23), and that BVES may recover in rates on a prospective basis beginning September 1, 2011, $6,475,708 which was the under-collection amount in the PPAC Balancing Account as of August 31, 2011. (Exhibit BVES-4, pp. 48-49, lines 6-28 and 1, respectively)

6.3. ***Change Name of PPAC and Three PPAC-Related Charges***. The Settling Parties confirm that BVES may change the names of the PPAC and the PPAC balancing account, as well as the names of three charges in the PPAC balancing account to more accurately describe their functions. The "Power Purchase Adjustment Clause" will be renamed the "Supply Adjustment Mechanism." The "PPAC Balancing Account" will be renamed the "Supply Adjustment Balancing Account." The "Power System Delivery Charge" will be renamed the "Transmission Charge," the "Energy Charge for Purchases" will be renamed the "Supply Charge," and the "Amortization Charge" will be renamed the "Supply Adjustment Charge." The procedures and accounting for the Supply Adjustment Balancing Account are set forth in the revised BVES Preliminary for the Supply Adjustment Mechanism, attached hereto as Exhibit H.

6.4. ***Adjustment of PPAC Charges, But No Net Change in Overall PPAC Charges*****.** The Settling Parties confirm that BVES may adjust the current charges in the PPAC as follows. A decrease in the existing Amortization Charge (which is being renamed the Supply Adjustment Charge) from $0.02246/kWh to $0.01729/kWh and an increase in the Power System Delivery Charge (which is being renamed the Transmission Charge) from approximately $0.0138/kWh, on average, to approximately $0.0330/kWh on average (transmission charges vary by customer class), and a decrease in the Energy Charge for Purchases (which is being renamed the Supply Charge) from approximately $0.0865/kWh, on average, to $0.0725/kWh, on average (supply charges vary by customer class). (Exhibit BVES-4, p. 73, lines 10-21) The Transmission Charges, Supply Charges and Supply Adjustment Charges for each customer class for 2013 are set forth in Exhibit G, attached hereto.

7. VARIOUS CHANGES TO SPECIAL CHARGES AND RULES

7.1. ***New Standby Service Rate*****:** The Settling Parties confirm that BVES may establish a new $10.50/kW standby rate for customers taking service under Schedule A-4 TOU and agree to a $1.50/kW standby rate for A-5 TOU secondary customers. BVES originally proposed a standby rate of $3.75/kW for A-5 TOU customers, and BBARWA rejected a standby charge for A-5 TOU customers. Exhibit K provides the tariff language for the new standby rates.

7.2. ***Changes to Special Service Charge and Rule 9.*** The Settling Parties confirm that BVES may increase various service and notice charges, including the service and reconnection charges, "turn off" notices, clean and show charges, and a new late payment charge. These changes are reflected in the revised Schedule SSC and revised Rule 9 attached hereto as Exhibit I and Exhibit J, respectively.

Rate	Component	Current	BVES	ORA	BBARWA**	Settlement
GSD	Service Charge	$0.23	$0.23	$0.23		$0.23
	Demand charge	$8	$10	$5		$9.00
	Base Energy	$0.0890	$0.1162	$0.0894		$0.10
A1	Service Charge per day	$0.36	$0.54	$0.21		$0.45
	Tier 1	$0.12980	$0.14763	$0.11500		TBD, one tier*
	Tier 2	$0.12980	$0.14763	$0.12800		
A2	Service Charge per day	$2.30	$2.42	$1.1500		$2.36
	Tier 1	$0.12892	$0.14607	$0.1190		TBD, one tier*
	Tier 2	$0.12892	$0.14607	$0.1200		
A3	Service Charge per day	$9.90	$3.30	$3.30		$6.60
	Demand	$7.00	$10.00	$7.00		$9.00
	Tier 1	$0.1271	$0.1578	$0.1271		TBD, one tier*
	Tier 2	$0.1271	$0.1578	$0.1440		
A-4 (TOU)	Service Charge per day	$16.40	$16.40	no objection		$16.40
	Demand	$7.00	$10.00	no objection		$10.00
	Minimum Charge		$3.00	no objection		$3.00
	Base Energy ($/kWh)	$0.11635	$0.13452	no objection		TBD*
	Standby Rate (kW/month)	zero	$10.50	no objection		$10.50
A-5 TOU/Secondary	Minimum charge (kW/mo.)	$0.75	$3.00	no objection	0**	$1.50
	service charge (per meter day)	$65.80	$65.80	no objection	$65.80	$65.80
	max demand ($/kW)	$4.30	$4.30	no objection		$4.30
	Firm Base on pk $/kW	$12.38	$12.38	no objection		$12.38
	non firm base on-pk$/kW	$6.00	$7.00	no objection		$7.00
	mid-pk $/kW &/kWh	$3.00	$3.50	no objection		$3.50
	Standby rate (kW/mo.)	0	$3.75	no objection	0	$1.50
	Base Energy ($/kWh)	$0.03167	$0.5095	no objection		TBD*
A-5 TOU/Primary	Minimum charge (kW/mo.)	$0.75	$1.50	no objection		$1.50
	service charge (per meter day)	$65.80	$65.80	no objection		$65.80
	max demand ($/kW)	$4.30	$4.30	no objection		$4.30
	Firm Bas on pk $/kW	$12.38	$12.38	no objection		$12.38
	non firm base on-pk$/kW	$5.25	$6.00	no objection		$6.00

	mid-pk $/kW &/kWh	$3.00	$3.50	no objection		$3.50
	Base Energy ($/kWh)	$0.03154	$0.03458	no objection		TBD*
Street Lighting	Service charge $/day	$0.2100	$0.2100	no objection		$0.2100
	Facilities Charge/Lamp/day	$0.539	$0.4340	no objection		$0.4340
	Energy Charge ($/kWh)	$0.01527	$0.15681	no objection		TBD**

7.3. ***Changes to Rule 2H, Added Facilities Are Withdrawn.*** The proposed modifications to Rule 2H are withdrawn by BVES.

7.4. ***Changes to Rule No.*** 7. The Settling Parties confirm that BVES may make changes in Rule 7, including a change regarding interest on deposit requirements and changes consistent with practices of other California electric utilities. These changes are reflected in the modified Rule 7 which is attached hereto as Exhibit L.

7.5. ***Changes to Rule 20, Undergrounding.*** The Settling Parties confirm that BVES may make changes in Rule 20 undergrounding provisions to be consistent with other utility Rule 20 provisions. These changes are reflected in the modified Rule 20 which is attached hereto as Exhibit M.

8. AGREED-UPON BASE RATE DESIGN PRINCIPLES

8.1. ***Base Rate Design.*** In order to develop final rates, the allocation of costs (i.e., revenue requirements) to each customer class is necessary. The Settling Parties were unable to reach agreement regarding the allocation of costs to each customer class. The Settling Parties did, however, reach agreement on rate design principles for all customer classes except residential customers. The litigation positions of BVES, ORA and BBARWA regarding rate design, along with the agreed-upon settlement rate designs, are summarized in the chart below.

BVES GRC 2013 Base Rate Principles

*** "TBD" means base energy rates will be calculated using the BVES rate design model applying the Rate Design principles and the revenue requirement allocation to the relevant rate class.**
**** BBARWA recommendation highlights rates applicable with zero consumption; Minimum Charge: applies under current rates, BVES proposal and Settlement; BBARWA recommends that minimum charge not apply with zero consumption.**

The rate design principles shall be applied in designing rates as follows:

1. First, apply the overall revenue requirement for 2013 of $19,700,000.

2. Next, allocate costs (*i.e.*, assign a portion of the overall base revenue requirement) to each customer class (e.g., revenue allocation) as determined by the Commission. No cost allocation is included in this Settlement.
3. Next, the Commission must determine the rate design principles for residential customers (e.g., permanent residential minimum charges and the percent change in base rates between tier 1 and tier 2, and tier 2 and tier 3).
4. Finally, apply the rate design principles noted above using the BVES rate design model in order to derive specific rates for each customer rate schedule. The BVES rate design model includes the agreed-upon forecast of customers and sales.

For example, in order to determine 2013 rates for A-1 commercial customers, a portion of the overall base revenue requirement of $19,700,000 must first be applied to the A-1 customer group. The Commission will determine this allocation. The rate design model will determine specific A-1 rates using the Rate Design Principles service charge rate of $0.45, and the revenue allocation to A-1 to determine a base rate energy rate ($/kWh).

8.2. ***Commission Determine Rate Design for Residential Class.*** The Settlement does not adopt rate design principles for residential rate classes. The Commission must approve rate design principles for residential customers.

9. RATES FOR 2013, 2014, 2015 and 2016.

The Settling Parties agree that base rates by customer class for 2013 should be developed as outlined in section 8 above. Once 2013 base rates have been so determined, rates for 2014, 2015 and 2016 shall be developed as follows.

1. The additional revenue requirements for 2014, 2015 and 2016, as compared to the 2013 revenue requirement, will be achieved through an adjustment to the energy rates for each customer class. For customer classes with multiple tiers, the energy rate shall be added to each tier.

2. The 2014 energy adjustment is equal to the change in 2014 base rate revenue requirements ($400,000) divided by the 2014 approved sales forecast

(144,694,448 kWh) =$0.002764. As set forth in the chart below, similar adjustments to the 2015 and 2016 energy rate charges would be made.

3. BVES is authorized to file a Tier 1 advice letter to implement the adjustment to energy rates for 2014, 2015 and 2016 as set forth in the chart below.

	2014	2015	2016
Base Revenue Requirement	$20,100,000	$20,500,000	$20,900,000
Total Sales (kWh)	144,694,448	147,888,461	149,479,404
Revenue increase	$400,000	$400,000	$400,000
Increase $/kwh	$0.00276445	$0.00270474	$0.00267595
Energy Rate Adjustment $/kwh	$0.00276445	$0.00546919	$0.00814514

10. OTHER AGREED-UPON TERMS AND CONDITIONS

10.1. ***Use of Monthly Target Values for BRRBA***. For purposes of implementing the Base Revenue Requirement Balancing Account ("BRRBA"), set forth in Exhibit A attached hereto, BVES recommended the seasonal monthly allocation method be used, whereas ORA recommended that 1/12 of the annual amount be used as the monthly portion of the annual revenue requirement in the BRRBA. The Settling Parties agree that, for the duration of this rate cycle and for purposes of implementing the BRRBA, BVES may use the monthly target values set forth below:

Sales MWh by Month	%/ Month
Jan	10.77%
Feb	9.39%
Mar	8.75%
Apr	7.65%
May	7.27%
Jun	7.12%
Jul	7.51%
Aug	7.57%
Sep	7.21%
Oct	7.28%
Nov	8.53%
Dec	10.95%

10.2. These values and other changes consistent with this Settlement have been added to the BRRBA Preliminary Statement attached hereto as Exhibit A.

10.3. ***Disposition of General Rate Case Memorandum Account Through the BRRBA.*** In an Interim Decision on Motion for Memorandum Account, BVES was authorized to establish a General Rate Case Revenue Requirement Memorandum Account ("GRC Memo Account"). The GRC Memo Account is to record rates based on BVES' 2012 authorized revenue requirement in order to track the change in revenue requirement adopted in this proceeding during the period between January 1, 2013 and the effective date of a final decision. Interest is authorized to accrue on the balance beginning January 1, 2013, based on the Board of Governors of the Federal Reserve's three-month commercial paper rate.

The Settling Parties agree that the disposition of the GRC Memo Account shall be implemented through the use of BVES' existing BRRBA. For the disposition of the amounts in the GRC Memo Account for 2013, the following BRRBA process shall be utilized. For 2013, BVES recorded in the BRRBA actual collections of $17,412,180. Utilizing the 2013 revenue requirement of $19,700,000 agreed to by the Settling Parties, there was a resulting 2013 revenue shortfall in the BRRBA of $2,289,912. It is agreed by the Settling Parties that if the Commission approves this Settlement Agreement, BVES is authorized to file a Tier 1 advice letter seeking recovery of $2,289,912, plus interest,[41] over a two-year amortization period through the existing BRRBA procedure.

For the disposition of the amounts in the GRC Memo Account for 2014, the following BRRBA process shall be utilized. The BRRBA revenue requirement for 2014 shall be revised to reflect the agreed-upon settlement amount of $20,100,000. This is reflected in the revised BRRBA attached hereto as Exhibit A. By revising the BRRBA revenue requirement for 2014 to reflect the agreed-upon settlement amount of $20,100,000, the

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41 BVES estimates that the under-collection of 2013 revenues plus accrued interest through July 1, 2014 would equal a short fall of $2,292,003, which amortized over two years would result in a 2013 BRRBA surcharge of $0.008068/kwh. This is an estimated surcharge, and is not the surcharge that would apply to low-income and possibly other customers. Furthermore, other BRRBA surcharges for shortfalls in revenues in previous years may also be in effect.

amounts in the GRC Memo Account for 2014 will be accounted for through the normal functioning of the BRRBA in 2015.

The Settling Parties agree that (i) with the adjustment of the BRRBA revenue requirements for 2013 and 2014 of $19,700,000 and $20,100,000, respectively, (ii) the implementation of a two-year surcharge for recovery of the 2013 shortfall of revenues, plus interest, as compared to the revenue requirement of $19,700,000, and (iii) the adjustment of the BRRBA revenue requirement of $20,100,000 for 2014 and the implementation of a surcharge or a credit in the event of a 2014 shortfall in or overcollection of revenues, the disposition of all amounts in the GRC Memo Account will have been achieved and the GRC Memo Account may be closed.

10.4. ***No Requirement for Updated RO Model***. ORA had requested that BVES upgrade its RO model to encompass all components of the RO in one file instead of six separate files. BVES took the position that no upgrade in its RO model was necessary. The Settling Parties agree that BVES is not required to upgrade its RO Model to encompass all components of the RO into one file.

10.5. ***Calculation of Administrative Costs***. ORA recommended that BVES calculate administrative costs on a total basis showing both the expense and capital portions in its next general rate case, and that BVES perform an administrative cost capital survey that analyzes the amount of administrative costs that are capitalized in its next general rate case. BVES took the position that ORA's recommendations were unnecessary because BVES' overhead ratios are based on ratios developed by GSWC to allocate a portion of the capitalized A&G costs to capital projects. The Settling Parties agree that BVES' administrative costs shall continue to be consistent with the Commission's determination of GSWC administrative costs as determined in GSWC's GRC.

10.6. ***Tax Memorandum Account***. ORA requested that the Commission order BVES to address the disposition of amounts in the tax memorandum account by separate application or, at the latest, BVES' next GRC application. BVES claimed that no such order is necessary and that BVES will address disposition in its next GRC filing. The

Settling Parties confirm that BVES will address the Tax Memorandum Account in BVES' next GRC application.

10.7. ***No Adjustment to Accumulated Depreciation Reserve Account***. ORA claimed that BVES' January 1, 2013 depreciation reserve account balance was understated as compared to the forecasted depreciation expense used to develop the revenue requirement in the 2009 GRC, and the depreciation reserve balance should be adjusted upward. BVES took the position that ORA's recommendation was contrary to Commission ratemaking policy and GAAP. The Settling Parties agree that no adjustment to BVES' depreciation reserve account shall be made. Neither ORA nor BVES concede their respective positions on this issue.

10.8. ***Next Rate Case Application Filed Prior to January 31, 2016***. The Settling Parties agree that BVES shall file its next general rate case application, with a 2017 Test Year, prior to January 31, 2016. The cost allocation and rate design components of the application shall be filed by March 1, 2016. The application shall include a four-year rate cycle. BVES may modify these filing dates for good cause through an appropriate procedural vehicle.

10.9. ***Recovery of Deferred Regulatory Expenses***. In its Application, BVES requested recovery of its forecasted regulatory expenses to be incurred in the processing of its Application. BVES forecasted that amount to be $2,342,000, which BVES proposed to amortize over the four-year GRC cycle at an annual rate of $585,000. ORA objected to BVES' request to recover the entire amount of regulatory expenses. ORA proposed that cost recovery should be limited to 50 percent of the requested amount. The settlement adopted an overall base rate revenue requirement and granted BVES flexibility to adjust expenses in order to achieve the settlement TY 2013 base rate revenue level. Therefore, the parties are in agreement that, for internal accounting purposes, BVES may include its original $585,000 for FERC Account 928 as an expense component of the settlement annual base rate revenues.

10.10. ***Except as Otherwise Provided in Settlement, Issues In Application Are Deemed Adopted***. The Settling Parties agree that all proposals or requests set forth in the

Application (except as withdrawn by BVES) are deemed adopted and accepted by the Settling Parties except as otherwise provided in this Settlement.

10.11. ***Further Actions.*** The Settling Parties acknowledge that this Settlement is subject to approval by the Commission. As soon as practicable after all the Settling Parties have signed the Settlement, the Settling Parties through their respective attorneys will prepare and file the Settlement Approval Motion. The Settling Parties will furnish such additional information, documents, or testimonies as the Commission may require for purposes of granting the Settlement Approval Motion and approving and adopting the Settlement.

10.12. ***No Personal Liability.*** None of the Settling Parties, or their respective employees, attorneys, or any other individual representative or agent, assumes any personal liability as a result of the Settling Parties executing this Settlement.

10.13. ***Non-Severability***. The provisions of this Settlement are non-severable. If any of the Settling Parties fails to perform its respective obligations under this Settlement, the Settlement will be regarded as rescinded.

10.14. ***Voluntary and Knowing Acceptance***. Each Settling Party hereto acknowledges and stipulates that it is agreeing to this Settlement freely, voluntarily, and without any fraud, duress, or undue influence by any other Settling Party. Each Settling Party has read and fully understands its rights, privileges, and duties under this Settlement, including its right to discuss this Settlement with its legal counsel, which has been exercised to the extent deemed necessary.

10.15. ***No Modification.*** This Settlement constitutes the entire Settlement among the Settling Parties regarding the matters set forth herein, which may not be altered, amended, or modified in any respect except in writing and with the express written and signed consent of all the Settling Parties hereto. All prior settlements, agreements, or other understandings, whether oral or in writing, regarding the matters set forth in this Settlement are expressly waived and have no further force or effect.

10.16. ***No Reliance.*** None of the Settling Parties has relied or presently relies on any statement, promise, or representation by any other Settling Party, whether oral or written, except as specifically set forth in this Settlement. Each Settling Party expressly assumes the risk of any mistake of law or fact made by such Settling Party or its authorized representative.

10.17. ***Counterparts.*** This Settlement may be executed in separate counterparts by the different Settling Parties hereto and all so executed will be binding and have the same effect as if all the Settling Parties had signed one and the same document. All such counterparts will be deemed to be an original and together constitute one and the same Settlement, notwithstanding that the signatures of all the Settling Parties and/or of a Settling Party's attorney or other representative do not appear on the same page of this Settlement or the related Settlement Approval Motion.

10.18. ***Binding upon Full Execution***. This Settlement will become effective and binding on each of the Settling Parties as of the date when it is fully executed. It will also be binding upon each of the Settling Parties' respective successors, subsidiaries, affiliates, representatives, agents, officers, directors, employees, and personal representatives, whether past, present, or future.

10.19. ***Commission Adoption Not Precedential.*** In accordance with Rule 12.5, the Settling Parties agree and acknowledge that unless the Commission expressly provides otherwise, its adoption of this Settlement does not constitute approval of or precedent regarding any principle or issue of law or fact in this or any other current or future proceeding.

10.20. ***Enforceability.*** The Settling Parties agree and acknowledge that after issuance of a Commission decision approving and adopting this Settlement, the Commission may reassert jurisdiction and reopen this proceeding to enforce the terms and conditions of this Settlement.

10.21. ***Finality.*** Once fully executed by the Settling Parties and adopted and approved by a Commission decision, this Settlement fully and finally settles any and all disputes among and between the Settling Parties in this proceeding, unless otherwise specifically provided in the Settlement.

10.22. ***No Admission.*** Nothing in this Settlement or related negotiations may be construed as an admission of any law or fact by any of the Settling Parties, or as precedential or binding on any of the Settling Parties in any other proceeding, whether before the Commission, in any court, or in any other state or federal administrative agency. Further, unless expressly stated herein this Settlement does not constitute an acknowledgement, admission, or acceptance by any of the Settling Parties regarding any issue of law or fact in this matter, or the validity or invalidity of any particular method, theory, or principle of ratemaking or regulation in this or any other proceeding.

10.23. ***Authority to Sign.*** Each Settling Party who executes this Settlement represents and warrants to each other Settling Party that the individual signing this Settlement and the related Settlement Approval Motion has the legal authority to do so on behalf of the Settling Party.

10.24. ***Limited Admissibility***. Each Settling Party signing this Settlement agrees and acknowledges that this Settlement will be admissible in any subsequent Commission proceeding for the sole purpose of enforcing the terms and conditions of this Settlement.

10.25. ***Estoppel or Waiver.*** Unless expressly stated herein, the Settling Parties' execution of this Settlement is not intended to provide any of the Settling Parties in any manner a basis of estoppel or waiver in this or any other proceeding.

10.26. ***Rescission.*** If the Commission, any court, or any other state or federal administrative agency, rejects or materially alters any provision of the Settlement, it will be deemed rescinded by the Settling Parties and of no legal effect as of the date of issuance of the Commission decision or final ruling, decision, or modification by any court or any other state or federal administrative agency, rejecting or materially altering the Settlement. The Settling Parties may negotiate in good faith regarding whether they want to accept the changes by the Commission, any court, or any other state or federal administrative agency, and resubmit a revised Settlement to the Commission.

11. Conclusion

11.1. Each of the Settling Parties has executed this Settlement as of the date appearing below their respective signatures.

IN WITNESS WHEREOF, the Settling Parties have executed this Settlement as of May 7, 2014.

GOLDEN STATE WATER COMPANY,
On Behalf of its Bear Valley Electric Service Division

____

Title:______________________________
Date: ___________

OFFICE OF RATEPAYER ADVOCATES

____

Title:____________________________
Date: ___________

CITY OF BIG BEAR LAKE

____

Title:_______________________________
Date: ___________

BIG BEAR AREA REGIONAL WASTEWATER AGENCY

____

Title:______________________________
Date: ___________

SNOW SUMMIT, INC.

____

Title:_____________________________
Date: ___________

Exhibit D

PRELIMINARY STATEMENTS

V. BASE REVENUE REQUIREMENT BALANCING ACCOUNT

Golden State Water Company ("GSWC") shall maintain the Base Revenue Requirement Balancing Account ("BRRBA") for its Bear Valley Electric Service ("BVES") Division as follows.

1. PURPOSE:
The purpose of the BRRBA is to record the difference between BVES adopted Base Revenue Requirements and the recorded revenues from base rates.

2. APPLICABILITY
The BRRBA shall apply to all customers base rate revenues.

3. RATES
Base rates are electric rates and related adjustments. Adjustments are required to amortize under-collections or over-collection in the BRRBA as authorized by the Commission from time to time.

4. AUTHORIZED BASE RATE REVENUE REQUIREMENTS
BVES' authorized annual base rate revenue requirements for the years 2013, 2014, 2015, and 2016 as reflected in the Settlement Agreement approved by the Commission in D.14-XX-XXX are set forth below:

Year	Annual Revenue Requirement
2013	$19,700,000
2014	$20,100,000
2015	$20,500,000
2016	$20,900,000

The authorized monthly revenue requirement shall be apportioned on a monthly basis using the following percentage allocation:

Sales MWh by Month	Month
Jan	10.77%
Feb	9.39%
Mar	8.75%
Apr	7.65%
May	7.27%
Jun	7.12%
Jul	7.51%
Aug	7.57%
Sep	7.21%
Oct	7.28%
Nov	8.53%
Dec	10.95%

5. ADJUSTMENTS TO THE REVENUE REQUIREMENT
The annual revenue requirement levels in Section 4 may be adjusted, if needed, by an update as a result of changes to BVES' allocation of GSWC's (i) General Office cost, (ii) common plant cost or (iii) employee pension and benefit costs, each as approved by the Commission in GSWC water operations application filed

before the Commission, or by some other appropriate proceeding that establishes a new BVES base rate revenue requirement or an addition to the BVES base rate revenue requirement shown in Section 4. The annual revenue requirement levels in Section 4 also may be adjusted, if needed, by an update as a result of the disposition of balances in the Pension Balancing Account, or advice letter filings regarding the completion and placement into commercial operation of the (i) Big Bear Boulevard Undergrounding Project (or a phase of the Big Bear Boulevard Undergrounding Project); or (ii) the Moonridge Substation Project.

6. TRANSFERS AND ADJUSTMENTS TO THE BRRBA BALANCE

From time to time the Commission may find that an amortization of a base rate memorandum or balancing account it authorized has run for the required number of months but that there remains an unamortized over- or under- collected balance at the end of the amortization period. The unamortized balances for such accounts may be transferred to the balance in the BRRBA if the costs covered by the account are base rate related costs.

7. ACCOUNTING PROCEDURES:

GSWC shall maintain the BRRBA by making entries at the end of each month as follow:

a. Recorded monthly base rate revenues.
b. Apportioned monthly allocation of the authorized annual base rate revenue requirement as described in Section 4.
c. Total net BRRBA balance: 7.a. minus 7.b.
d. GSWC shall apply interest to the average net balance in the BRRBA account at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month as reported in the Federal Reserve Statistical Release, H.15, or its successor publication. Accumulated interest will be included in the amount on which interest is charged, but will be identified as a separate component of the BRRBA account.

8. EFFECTIVE DATE

As reflected in the Settlement Agreement approved by the Commission in D.14-XX-XXX, the revenue requirements for 2013, 2014, 2015 and 2016 are effective as of January 1, 2013, January 1, 2014, January 1, 2015 and January 1, 2016, respectively.

9. ACCOUNT DISPOSITION

The disposition of the balance in the BRRBA at the close of each year, plus any transfers or adjustments authorized to be made to the BRRBA, will be addressed by GSWC in a Tier 2 Advice Letter filing if the amount of the under- or over-collection is equal to or greater than 5% of the revenue requirement established for the previous twelve months. Should such a trigger be met, GSWC may file the required advice letter with the necessary amortization charge expected to amortize the balance over the next twelve months.

Exhibit E

PRELIMINARY STATEMENTS

BB. PENSION BALANCING ACCOUNT

Golden State Water Company ("GSWC") shall maintain the Pension Balancing Account ("PBA") for its Bear Valley Electric Service ("BVES") Division as follows.

1. PURPOSE:
   The purpose of the PBA is to track the difference between
   a. Pension costs allocated to BVES by the Commission in the most recent General Rate Case application for GSWC; and
   b. Actual BVES pension costs based on Accounting Standard Codification 715-10 ("ASC 715-10"), Compensation – Retirement Benefits.

2. APPLICABILITY:
   The PBA does not have a rate component.

3. ACCOUNTING PROCEDURE:
   GSWC shall maintain the PBA by making entries at the end of each month as follows:

   a. An entry shall be made to the PBA at the end of each month to record the difference between the pension costs allocated to BVES by the Commission, in the most recent General Rate Case application for GSWC, divided by 12, and the actual BVES monthly-recorded pension costs based on ASC 715-10.
   b. Interest shall accrue to the PBA on a monthly basis by applying a rate equal to one-twelfth of the 3-month Commercial Paper Rate, as reported in the Federal Reserve Statistical Release H.15, to the average of the beginning-of-month and the end-of-month.
   c. GSWC is authorized to update the pension costs referenced in 1A above via a Tier 1 advice letter whenever the Commission adopts new pension cost allocations to BVES in a GSWC General Rate Case.

4. Effective Date
   The PBA shall be effective as of January 1, 2013.

5. DISPOSITION
   By March of each year GSWC will transfer any over- or under-collection in the PBA, with interest, to the Base Revenue Requirement Balancing Account and such transferred amount shall be administered in accordance with the provisions of the Base Revenue Requirement Balancing Account.

Exhibit E

PRELIMINARY STATEMENTS

CC. ENERGY EFFICIENCY BALANCING ACCOUNT

Golden State Water Company ("GSWC") shall maintain the Energy Efficiency Balancing Account ("EEBA") for its Bear Valley Electric Service ("BVES") Division as follows.

1. Purpose:
   The purpose of the EEBA is to track the Public Purpose Program Surcharge ("PPP Surcharge") funds allocable to the Energy Efficiency ("EE") Program and EE Program costs. This is an interest bearing one-way account where over-expenditures are not recovered.

2. Applicability:
   The EEBA does not have a rate component.

3. Definitions:
   a. Effective Date: Implementation of the EEBA component of the PPP Surcharge to recover the Total Authorized Revenue Requirement shall be effective July 1, 2014 or the effective date of the decision in A. 12-02-013.
   b. FF&U: The applicable Franchise Fee and Uncollectibles (FF&U) percentages will be those specified in the Commission's decision in BVES' most recent general rate case.
   c. Interest Rate: The Interest Rate shall be 1/12 of the most recent interest on Commercial Paper (prime, 3 months), published in the Federal Reserve Statistical Release, H.15. Should publication of the interest rate on Commercial Paper (prime, 3 months) be discontinued, interest will so accrue at the rate of 1/12 of the most recent month's interest rate on Commercial Paper, which most closely approximates the rate that was discontinued, and which is published in the Federal Reserve Statistical Release, H.15, or its successor publication.
   d. EEBA Revenue: The monthly EEBA revenue is determined by multiplying the net unbundled PPC-OLI and PPC-LI Surcharge billed during the month by the appropriate EE Program allocation factor as specified in the PPPAM Preliminary Statement.
   e. EEBA Expenses: EE Program authorized expenses recorded to the EEBA and consistent with EE Program budgets authorized by the Commission.
   f. Total Authorized EEBA Revenue Requirement: the total Authorized EEBA Revenue Requirement shall be the current Commission–adopted budget for the EE Program, plus amortization of any EEBA over- or under-collection from a previous period as authorized by the Commission.
   g. Total Authorized BVES Public Purpose Programs Revenue Requirement: the total authorized BVES PPP Revenue Requirement shall be the sum of the Commission- adopted Revenue Requirement associated with all of BVES' Public Purpose Programs, including both Public Good Programs (legislatively mandated) and other Commission-authorized Public Programs. Such amounts are to be detailed and stated in the Public Purpose Program Adjustment Mechanism (PPPAMP) Preliminary Statement.

4. Accounting Procedure:
   a. A credit entry equal to the monthly EEBA Revenue as specified in section 3.d.
   b. A debit entry equal to the EEBA Expenses as specified in section 3.e.
   c. A debit entry equal to the FF&U specified in section 3.b. above times EEBA Revenue.
   d. An entry equal to the monthly interest as specified in section 3.c. applied to the average of the beginning and ending balances in the EEBA.
   If the above calculations produce a negative amount (undercollection), such amount will be debited to the EEBA. If the above calculation produces a positive amount (over collection), such amount will be credited to the EEBA. While the EEBA is a one-way balancing account, any EEBA Revenue recorded in the EEBA exceeding authorized program costs expended shall be carried forward to supplement the subsequent year's program or accounted for as otherwise directed by the Commission.

5. Annual Review and Revision of the EEBA Revenue Requirement.
Each year by April, BVES shall review the EE program and the balance between the EEBA Revenue collected and the EEBA Expenses expected over the following year. In addition:

a. BVES may propose an update of the EEBA Revenue Requirement if there is a need to achieve a closer balance between EEBA Revenue and EEBA Expenses as long as this proposal is within guidelines provided by the Commission.
b. BVES may propose an update of EEBA component of the PPP Surcharges to amortize an under or over collection of the EEBA based on the balance.
c. Should BVES propose to update the EEBA Revenue Requirement, it must also update the Total PPP Revenue Requirement to reflect such changes it proposes in the EEBA revenue requirement and, if necessary, specify an associated change to the PPP Surcharge, including a revision to the percentage allocation factor to determine the EEBA's share of the Total PPP Revenue Requirement.
d. If BVES has no updated or changes to propose, BVES will take no action. If BVES has any updates or changes to proposed, it will do so through the Advice Letter process.

PRELIMINARY STATEMENTS

DD. SOLAR INITIATIVE BALANCING ACCOUNT

Golden State Water Company ("GSWC") shall maintain the Solar Initiative Balancing Account ("SIBA") for its Bear Valley Electric Service ("BVES") Division as follows.

1. Purpose:
The purpose of the SIBA is to track the Public Purpose Program Surcharge (PPP Surcharge) funds allocable to the Solar Initiative ("SI") Program and SI Program costs. This is an interest bearing one-way account where over-expenditures are not recovered.

2. Applicability:
The SIBA does not have a rate component.

3. Definitions:
   a. Effective Date: Implementation of the SIBA component of the PPP Surcharge to recover the Total Authorized SIBA Revenue Requirement shall be effective July 1, 2014 or the effective date of the decision in A. 12-02-013.
   b. FF&U: The applicable Franchise Fee and Uncollectibles ("FF&U") percentages will be those specified in the Commission's Decision in BVES' most recent general rate case.
   c. Interest Rate: The Interest Rate shall be 1/12 of the most recent interest on Commercial Paper (prime, 3 months), published in the Federal Reserve Statistical Release, H.15. Should publication of the interest rate on Commercial Paper (prime, 3 months) be discontinued, interest will so accrue at the rate of 1/12 of the most recent month's interest rate on Commercial Paper, which most closely approximates the rate that was discontinued, and which is published in the Federal Reserve Statistical Release, H.15, or its successor publication.
   d. SIBA Revenue: the monthly SIBA revenue is determined by multiplying the net unbundled PPC-OLI and PPC-LI Surcharges billed during the month by the appropriate SI Program allocation factor as specified in the PPPAM Preliminary Statement.
   e. SIBA Expenses: SI Program authorized expenses recorded to the SIBA.
   f. Total Authorized SIBA Revenue Requirement: The total Authorized SIBA Revenue Requirement shall be the current Commission – adopted budget associated with the SI Program, plus amortization of any SI over- or under-collection from a previous period authorized by the Commission.
   g. Total Authorized BVES Public Purpose Programs Revenue Requirement: the total authorized BVES PPP Revenue Requirement shall be the sum of the Commission- adopted Revenue Requirement associated with all of BVES' Public Purpose Programs, including both Public Good Programs (legislatively mandated) and other Commission-authorized Public Programs. Such amounts are to be detailed and stated in the Public Purpose Program Adjustment Mechanism (PPPAMP) Preliminary Statement.

4. Accounting Procedure:
   a. A credit entry equal to the monthly SIBA Revenue as specified in section 3.d.
   b. A debit entry equal to the SIBA Expenses as specified ins section 3.e.
   c. A debit entry equal to the FF&U specified in section 3.b. above times SIBA Revenue.
   d. An entry equal to the monthly interest as specified in section 3.c. applied to the average of the beginning and ending balances in the SIBA.

   If the above calculations produce a negative amount (undercollection), such amount will be debited to the SIBA. If the above calculation produces a positive amount (over collection), such amount will be credited to the SIBA. While the SIBA is a one-way balancing account, any PPP Surcharge revenues recorded in the SIBA exceeding authorized program costs expended shall be carried forward to supplement the subsequent year's program or accounted for as otherwise directed by the Commission.

5. Annual Review and Revision of the SIBA Revenue Requirement.

Each year by April, BVES shall review the SI program, the reasonableness of costs charged to SIBA, and the balance between the SIBA Revenue collected and the SIBA Expenses expected over the following year. In addition:

   a. BVES may propose an update of the SIBA Revenue Requirement if there is a need to achieve a closer balance between SIBA Revenue and SIBA Expenses as long as this proposal is within guidelines provided by the Commission.

b. BVES may propose an update of SIBA component of the PPP Surcharges to amortized an under or over collection of the SIBA based on the balance.
c. Should BVES propose to update the SIBA Revenue Requirement, it must also updated the Total PPP Revenue Requirement to reflect such changes it proposes in the SIBA revenue requirement and, if necessary, specify an associated change to the PPP Surcharge, including a revision to the percentage allocation factor to determine the SIBA's share of the Total PPP Revenue Requirement.
d. If BVES has no updated or changes to propose, BVES will take no action. If BVES has any updates or changes to proposed, it will do so through the Advice Letter process.

Exhibit G

PRELIMINARY STATEMENTS

EE. Bear Valley Solar Initiative Program

PURPOSE
The purpose of this program is to promote the installation of residential solar photovoltaic (PV) electric generation equipment by customers. The program will pay customers an incentive upon completion, inspection and interconnection of program approved projects.

APPLICABILITY
This program is open to all residential customers.

MONTHLY BILLING
Customers will be billed according to the terms described in BVES' net metering tariff, Schedule NEM.

DEFINITIONS

1. Host Customer: An individual or entity that meets all the following criteria: 1) has legal rights to occupy the site, 2) receives retail level electric service from Bear Valley Electric Service, 3) is the utility customer of record at the site, 4) is connected to the electric grid, and 5) is the recipient of the net electricity generated from the solar equipment.
2. PRMS: Performance Reporting and Monitoring Service (required for systems 10kW or larger).

INCENTIVES
Incentives will be paid based on expected output of the installed solar PV system as calculated by an approved program calculator. Incentive will be paid per watt and will decline as the program reaches capacity steps as shown in table below. Current incentive information will be maintained on the program website.

Bear Valley Solar Program Incentives and Steps

Steps	Incentive ($/watt)	Capacity (KW) Incentive
1	$1.60	155
2	$1.30	180
3	$1.09	215
4	$0.94	250
Total		800

Payment amount will equal the current incentive level at the time of application submittal multiplied by the estimated alternative current (AC) output of the system. The AC output of each system will be estimated in kilowatts (kW) based on installation characteristics and design factors and calculated using an approved program calculator.

The maximum eligible incentive for systems above 5kW in capacity will be equivalent to the size of a system calculated to offset 90 percent of the average electrical usage at the project site over the previous 12-month period. For sites without a 12-month usage history, the maximum incentive will be 90 percent of estimated annual usage.

INCENTIVE APPLICATION PROCESS
1. An energy efficiency audit is recommended to be completed by the host customer before installing solar, though the audit document is not required as part of the application submittal. Acknowledgement of the host customer completing the audit will be listed on the Energy Efficiency Disclosure Form.
2. Customer will select a licensed solar contractor.
3. Once installation is complete and the system has been interconnected, the customer will complete and submit one application to receive the incentive payment. Forms will include:
   - Signed Incentive Claim Form
   - Program incentive calculator output
   - Signed Energy Efficiency Disclosure Form
   - One of the following: installation contract, leasing agreement, or purchase of equipment receipt
   - Interconnection approval will be provided by BVES.

   All forms, material and instructions will be available on the program website.

SPECIAL CONDITIONS

1. Customer is responsible for selecting and contracting with a qualified solar installer. A list of solar contractors will be maintained on the program website.
2. The minimum system size eligible for an incentive is 1kW. The maximum incentive available for any project is 50 kW.
3. Solar energy systems must carry a minimum 10-year manufacturer warranty and must be permanently installed.
4. Program information will be reported to the Commission in the 2017 General rate Case application.
5. For systems under 10 kW, the customer will provide an accessible production meter base. BVES will provide a meter capable of measuring the monthly energy production of the customer's system (BVES will install mandatory performance meters on 1 in 15 installed solar systems).
6. For systems 10 kW and larger, PRMS service is required and interval kWh production data is to be reported to the program administrator on a quarterly basis for 1 year.
7. All systems must meet all applicable regulations including building and electrical codes and be inspected prior to receiving incentive payment.
8. Program rules and guideline may change periodically. The latest program information, including forms, instructions and current incentive levels will be available on the program website.
9. BVES retains the right to modify or terminate the program based on customer response or other factors. Requests for modification or termination of the program would be made through an advice letter filling.
10. Solar system installation may be inspected to ensure program compliance.
11. The owner of the generation facility will retain the ownership of any renewable energy credits (RECs) associated with generation of electricity from the facility.

Exhibit H

PRELIMINARY STATEMENTS

K. PUBLIC PURPOSE PROGRAM ADJUSTMENT MECHANISM

Golden State Water Company ("GSWC") shall maintain the Public Purpose Program Adjustment Mechanism ("PPPAM") for its Bear Valley Electric Service ("BVES") Division as follows.

1. Purpose: The purpose of the PPPAM is to specify the budgets and revenue requirement levels for each public purpose program identified below ("Public Purpose Programs"); to establish the Public Purpose Program Surcharge ("PPP Surcharge") levels; and to specify the allocation factor for each Public Purpose Program to be used to allocate the monthly funds produced by the PPP Surcharges (net of Franchise Fees and Uncollectibles) to each Public Purpose Program as authorized by the Commission.

2. Applicability: The PPPAM is not a rate; it identifies the rate levels and percentages for determining the amount of total unbundled revenue to be allocated to each Public Purpose Program's balancing account. The PPP Surcharge shall apply to each utility rate schedule, except as otherwise provided in the Preliminary Statements.

3. Definitions:
   a. Effective Date: The PPPAM shall be effective on April 1, 2009.
   b. FF&U: The applicable Franchise Fee and Uncollectible ("FF&U") percentages will be those specified in the Commission's decision in BVES' most recent General Rate Case or applicable proceeding.
   c. Public Purpose Programs: The Public Purpose Programs covered by the PPPAM include:
      1) CARE: California Alternative Rates for Energy.
      2) LIEE: Low Income Energy Efficiency.
      3) CEC-RD&D: Program: CEC's Research, Development & Demonstration
      4) CEC-Renewables: Program, CEC's Based Renewables.
      5) Energy Efficiency ("EE") Program.
      6) Solar Initiative Program

   d. Revenue Requirement: The revenue requirement associated with a specific Public Purpose Program includes the sum of all budgeted expenses adopted by the Commission associated with the Public Purpose Program, including discounts to the otherwise applicable tariff. Budgeted expenses can include mandated contributions to an agency; an allocation of BVES administrative & general expenses; and direct labor costs incurred by BVES in executing the Public Purpose Program consistent with guidelines authorized by the Commission. Such direct Program costs may consist of discounts, incentives, grants, or loans to customers as authorized by the Commission. In addition, the revenue requirement may include an amount equal to an over-collection or under-collection of the balancing account associated with a specific Public Purpose Program.
   e. Total PPP Revenue Requirement: The authorized Total PPP Revenue Requirement shall be the sum of Revenue Requirements associated with each of the Public Purpose Programs, including both Public Goods Programs (legislatively mandated), under- or over-collection amounts in the balancing accounts of the Public Purpose Programs from a previous period, applicable FF&U costs and all other Commission-authorized Public Purpose Programs costs. The Commission may change the Total PPP Revenue Requirement without changing the associated PPP Surcharges or the PPP Allocation Factors (see definitions below).
   f. Public Purpose Program Surcharge (PPP Surcharge): The PPP Surcharge, expressed on a $/kWh basis, is used to recover the Total PPP Revenue Requirement. The PPP Surcharge will be divided into two separate surcharges and applied to two groups of customers as follows:
      1) The PPP Surcharge applicable to low income customers (CARE) will be the PPC-LI Surcharge.
      2) The PPP Surcharge applicable to other than low income customers will be the PPC-OLI Surcharge.

The PPC-LI Surcharge and the PPC-OLI Surcharge will be computed by taking the sum of the Revenue Requirements applicable to each of the two groups of customers above and dividing each such sum by the corresponding sales forecast adopted by the Commission for each of the two groups of customers. However, the Commission may choose to increase or decrease the Total PPP Revenue Requirement without changing the PPC-LI Surcharge or the PPC-OLI Surcharge.

g. Net PPPAM Revenue: The Net PPPAM Revenue is the revenue produced by the PPC-LI Surcharge and the PPC-OLI Surcharge, net of FF&U (as designated in the appropriate section of this Preliminary Statement), the allocation of which becomes the funds that are credited to the balancing account for each Public Purpose Program.

h. Public Purpose Program (PPP) Allocation Factor: The Public Purpose Program Allocation Factor is the percentage of Net PPPAM Revenue that is attributed to each Public Purpose Program. The sum of all such PPP Allocation Factors for each of the PPC-LI Surcharge revenues and the PPC-OLI Surcharge revenues must add to 100%. The Public Purpose Program Allocation Factors may be changed at the time of BVES' annual review and may or may not be accompanied by a change in the PPC-LI Surcharge or the PPC-OLI Surcharge.

4. Annual PPPAM Review: Each year by April 1, BVES shall review all Public Purpose Programs, and if deemed necessary, BVES may make appropriate changes to Public Purpose Program budgets, Public Purpose Program Allocation Factors, the PPC-LI Surcharge and the PPC-OLI Surcharge associated with the PPPAM using the procedure outlined in section 6 below. BVES may also provide:

a. A proposal for an update of the Total PPP Revenue Requirement and PPP Surcharges if there is a need to achieve a closer balance between Net PPPAM Revenues and Total PPP Revenue Requirement.

b. An update of the Public Purpose Program Allocation Factors at any time it is deemed necessary.

5. PPPAM Program Budgets, Revenue Requirement and Allocation Factors: The following are the current adopted budgets, total revenue requirement levels and allocation factors applicable to each Public Purpose Program authorized by the Commission, including the last authorized FF&U factors:

PPPAM Table of Total PPP Revenue Requirements and Allocation Factors
(Amounts Shown Below Are $1,000)

Element or Component	PPP Rev Reqmnt	CARE	LIEE	CEC-R&D	CEC-Renewables	Energy Efficiency	Solar Initiative
Authorized Budget	$847.0	$172.4	$229.6	$56.0	$27.2	$200.0	$161.8
Balancing Acct Amortization	$141.4	$113.5	$27.9	$0.0	$0.0	$0.0	$0.0
Franchise Fees & Uncollectibles*	$11.9	$3.8	$3.4	NA	NA	$2.6	$2.1
Total PPP Revenue Requirement	$1,000.3	$289.7	$261.1	$56.0	$27.2	$202.6	$163.9
PPC-LI Surcharge	$0.00518	NA	$0.00190	$0.00041	$0.00020	$0.00148	$0.00119
PPC-LI Surcharge Allocation Factor %	100.0000%	NA	36.6795%	7.9151%	3.8610%	28.5714%	22.9730%
PPC-OLI Surcharge	$0.00738	$0.00220	$0.00190	$0.00041	$0.00020	$0.00148	$0.00119
PPC-OLI Surcharge Allocation Factor %	100.0000%	29.8103%	25.7453%	5.5556%	2.7100%	20.0542%	16.1247%

* Authorized in last general rate case
NA Indicates "not applicable"

6. Accounting Procedure: BVES shall maintain the table above to specify the latest authorized Total PPP Revenue Requirement levels and Allocation Factors for each Public Purpose Program. The Allocation Factors in the table shall be used to allocate the Net PPPAM Revenue with respect to the applicable PPP Surcharge to each Public Purpose Program's balancing account. The accounting procedure used each month as follows:

a. Each month the Net PPPAM Revenue resulting from the application of the PPC-LI Surcharge shall be allocated to the Public Purpose Programs based upon the PPC-LI Surcharge Allocation Factors above and that amount will become the funds to be credited to the appropriate Public Purpose Program balancing account associated with the PPC-LI Surcharge.

b. Each month the Net PPPAM Revenue resulting from the application of the PPC-OLI Surcharge shall be allocated to the Public Purpose Programs based upon the PPC-OLI Surcharge Allocation Factors above and that amount will become the funds to be credited to the appropriate Public Purpose Program balancing account associated with the PPC-OLI Surcharge.

c. BVES may submit by advice letter updates, changes and modifications to the Public Purpose Program budgets, Public Purpose Program Allocation Factors, the PPC-LI Surcharge and the PPC-OLI Surcharge.

d. If BVES proposes no updates, changes or modifications to the Public Purpose Program budgets, Public Purpose Program Allocation Factors, the PPC-LI Surcharge or the PPC-OLI Surcharge, BVES will take no action.

Exhibit I

2013 Settlement Supply Rates
(Does not include Base Rate components)

Line #	Rate Schedule	Season	Tier / TOU	Supply Dem. Chrg. $/kW	Trans $/kWh	Supply $/kWh	Supply Adj. $/kWh	SUBTOTAL SAM Rates
Permanent Residential								
1	D (Perm)	Sumr	Tier #1 Baseline (BL)		$0.03300	$0.02307	$0.01729	**$0.07336**
2	D (Perm)	Sumr	Tier #2 130% BL		$0.03300	$0.04667	$0.01729	**$0.09696**
3	D (Perm)	Sumr	Tier #3 All Other Use		$0.03300	$0.13482	$0.01729	**$0.18511**
4	D (Perm)	Wntr	Tier #1 Baseline (BL)		$0.03300	$0.02307	$0.01729	**$0.07336**
5	D (Perm)	Wntr	Tier #2 130% BL		$0.03300	$0.04667	$0.01729	**$0.09696**
6	D (Perm)	Wntr	Tier #3 All Other Use		$0.03300	$0.13482	$0.01729	**$0.18511**
7								
8	D (Employee)	Sumr	Tier #1 Baseline (BL)		$0.01650	$0.01154	$0.00865	**$0.03668**
9	D (Employee)	Sumr	Tier #2 130% BL		$0.01650	$0.02334	$0.00865	**$0.04848**
10	D (Employee)	Sumr	Tier #3 All Other Use		$0.01650	$0.06741	$0.00865	**$0.09256**
11	D (Employee)	Wntr	Tier #1 Baseline (BL)		$0.01650	$0.01154	$0.00865	**$0.03668**
12	D (Employee)	Wntr	Tier #2 130% BL		$0.01650	$0.02334	$0.00865	**$0.04848**
13	D (Employee)	Wntr	Tier #3 All Other Use		$0.01650	$0.06741	$0.00865	**$0.09256**
14								
15	D-LI (CARE)	Sumr	Tier #1 Baseline (BL)		$0.02640	$0.01846	$0.01383	**$0.05869**
16	D-LI (CARE)	Sumr	Tier #2 130% BL		$0.02640	$0.03734	$0.01383	**$0.07757**
17	D-LI (CARE)	Sumr	Tier #3 All Other Use		$0.02640	$0.10786	$0.01383	**$0.14809**
18	D-LI (CARE)	Wntr	Tier #1 Baseline (BL)		$0.02640	$0.01846	$0.01383	**$0.05869**
19	D-LI (CARE)	Wntr	Tier #2 130% BL		$0.02640	$0.03734	$0.01383	**$0.07757**
20	D-LI (CARE)	Wntr	Tier #3 All Other Use		$0.02640	$0.10786	$0.01383	**$0.14809**
21								
22	**Seasonal Residential**							
23	DO (Seas)	Sumr	Tier #1		$0.03300	$0.10855	$0.01729	**$0.15884**
24	DO (Seas)	Sumr	Tier #2		$0.03300	$0.10855	$0.01729	**$0.15884**
25	DO (Seas)	Wntr	Tier #1		$0.03300	$0.10855	$0.01729	**$0.15884**
26	DO (Seas)	Wntr	Tier #2		$0.03300	$0.10855	$0.01729	**$0.15884**
27								
28	**Master Metered Apartments (No Submeters)**							
29	DM (Perm)	Sumr	Tier #1 Baseline (BL)		$0.03300	$0.02307	$0.01729	**$0.07336**
30	DM (Perm)	Sumr	Tier #2 130% BL		$0.03300	$0.04667	$0.01729	**$0.09696**
31	DM (Perm)	Sumr	Tier #3 All Other Use		$0.03300	$0.13482	$0.01729	**$0.18511**
32	DM (Perm)	Wntr	Tier #1 Baseline (BL)		$0.03300	$0.02307	$0.01729	**$0.07336**
33	DM (Perm)	Wntr	Tier #2 130% BL		$0.03300	$0.04667	$0.01729	**$0.09696**
34	DM (Perm)	Wntr	Tier #3 All Other Use		$0.03300	$0.13482	$0.01729	**$0.18511**
35								
36	**Master Metered Mobilehome Parks**							
37	DMS Meter	Sumr	Service Charge		NA	NA	NA	**NA**
38	DMS Meter	Wntr	Service Charge		NA	NA	NA	**NA**
39	DMS Meter	Sumr	Discount Per Occupied Unit		NA	NA	NA	**NA**
40	DMS Meter	Wntr	Discount Per Occupied Unit		NA	NA	NA	**NA**
41	*Apply to Submetered Acct Under DMS*							
42	D (Perm)	Sumr	Tier #1 Baseline (BL)		$0.03300	$0.02307	$0.01729	**$0.07336**
43	D (Perm)	Sumr	Tier #2 130% BL		$0.03300	$0.04667	$0.01729	**$0.09696**
44	D (Perm)	Sumr	Tier #3 All Other Use		$0.03300	$0.13482	$0.01729	**$0.18511**
45	D (Perm)	Wntr	Tier #1 Baseline (BL)		$0.03300	$0.02307	$0.01729	**$0.07336**
46	D (Perm)	Wntr	Tier #2 130% BL		$0.03300	$0.04667	$0.01729	**$0.09696**
47	D (Perm)	Wntr	Tier #3 All Other Use		$0.03300	$0.13482	$0.01729	**$0.18511**
48								
49	D-LI (Perm)	Sumr	Tier #1 Baseline (BL)		$0.02686	$0.01846	$0.01383	**$0.05914**
50	D-LI (Perm)	Sumr	Tier #2 130% BL		$0.02686	$0.03734	$0.01383	**$0.07802**
51	D-LI (Perm)	Sumr	Tier #3 All Other Use		$0.02686	$0.10786	$0.01383	**$0.14854**
52	D-LI (Perm)	Wntr	Tier #1 Baseline (BL)		$0.02686	$0.01846	$0.01383	**$0.05914**
53	D-LI (Perm)	Wntr	Tier #2 130% BL		$0.02686	$0.03734	$0.01383	**$0.07802**
54	D-LI (Perm)	Wntr	Tier #3 All Other Use		$0.02686	$0.10786	$0.01383	**$0.14854**
55								
56	DO (Seas)	Sumr	Tier #1		$0.03300	$0.10855	$0.01729	**$0.15884**

Line #	Rate Schedule	Season	Tier / TOU	Supply Dem. Chrg. $/kW	Trans $/kWh	Supply $/kWh	Supply Adj. $/kWh	SUBTOTAL SAM Rates
57	DO (Seas)	Sumr	Tier #2		$0.03300	$0.10855	$0.01729	**$0.15884**
58	DO (Seas)	Wntr	Tier #1		$0.03300	$0.10855	$0.01729	**$0.15884**
59	DO (Seas)	Wntr	Tier #2		$0.03300	$0.10855	$0.01729	**$0.15884**
60								
61	**Commercial (Small to Large)**							
62	A-1	Sumr	Tier #1		$0.03300	$0.05372	$0.01729	**$0.10401**
63	A-1	Sumr	Tier #2		$0.03300	$0.10462	$0.01729	**$0.15491**
64	A-1	Wntr	Tier #1		$0.03300	$0.05372	$0.01729	**$0.10401**
65	A-1	Wntr	Tier #2		$0.03300	$0.10462	$0.01729	**$0.15491**
66								
67	A-2	Sumr	Tier #1		$0.03300	$0.05067	$0.01729	**$0.10096**
68	A-2	Sumr	Tier #2		$0.03300	$0.10157	$0.01729	**$0.15186**
69	A-2	Wntr	Tier #1		$0.03300	$0.05067	$0.01729	**$0.10096**
70	A-2	Wntr	Tier #2		$0.03300	$0.10157	$0.01729	**$0.15186**
71								
72	A-3	Sumr	Demand					
73	A-3	Sumr	Tier #1		$0.03300	$0.04417	$0.01729	**$0.09446**
74	A-3	Sumr	Tier #2		$0.03300	$0.09507	$0.01729	**$0.14536**
75	A-3	Wntr	Demand					
76	A-3	Wntr	Tier #1		$0.03300	$0.04417	$0.01729	**$0.09446**
77	A-3	Wntr	Tier #2		$0.03300	$0.09507	$0.01729	**$0.14536**
78								
79	GSD	Sumr	Demand					
80	GSD	Sumr	Tier #1		$0.03300	$0.03987	$0.01729	**$0.09016**
81	GSD	Wntr	Demand					
82	GSD	Wntr	Tier #1		$0.03300	$0.03987	$0.01729	**$0.09016**
83								
84	**Very Large Customer Time-Of-Use**							
85	A-4 TOU	Sumr	Fixed Charges					
86	A-4 TOU	Sumr	Max Demand					
87	A-4 TOU	Sumr	On-Pk $/kW & /kWh	$0.00	$0.03300	$0.12462	$0.01729	**$0.17491**
88	A-4 TOU	Sumr	Mid-Pk $/kW & /kWh		$0.03300	$0.09122	$0.01729	**$0.14151**
89	A-4 TOU	Sumr	Off-Pk $/kW & /kWh		$0.03300	$0.06895	$0.01729	**$0.11924**
90	A-4 TOU	Wntr	Fixed Charges					
91	A-4 TOU	Wntr	Max Demand					
92	A-4 TOU	Wntr	On-Pk $/kW & /kWh	$0.00	$0.03300	$0.12462	$0.01729	**$0.17491**
93	A-4 TOU	Wntr	Mid-Pk $/kW & /kWh		$0.03300	$0.09122	$0.01729	**$0.14151**
94	A-4 TOU	Wntr	Off-Pk $/kW & /kWh		$0.03300	$0.06895	$0.01729	**$0.11924**
95								
96	A-5 TOU/Sec	Sumr	Fixed Charges					
97	A-5 TOU/Sec	Sumr	Max Demand					
98	A-5 TOU/Sec	Sumr	FIRM On-Pk $/kW & /kWh	**$4.60**	$0.03300	$0.06856	$0.01729	**$0.11885**
99	A-5 TOU/Sec	Sumr	NON-FIRM On-Pk $/kW & /kWh	**$4.60**	$0.03300	$0.06856	$0.01729	**$0.11885**
100	A-5 TOU/Sec	Sumr	Mid-Pk $/kW & /kWh		$0.03300	$0.03761	$0.01729	**$0.08790**
101	A-5 TOU/Sec	Sumr	Off-Pk $/kW & /kWh		$0.03300	$0.02421	$0.01729	**$0.07450**
102	A-5 TOU/Sec	Wntr	Fixed Charges					
103	A-5 TOU/Sec	Wntr	Max Demand					
104	A-5 TOU/Sec	Wntr	FIRM On-Pk $/kW & /kWh	**$4.60**	$0.03300	$0.06856	$0.01729	**$0.11885**
105	A-5 TOU/Sec	Wntr	NON-FIRM On-Pk $/kW & /kWh	**$4.60**	$0.03300	$0.06856	$0.01729	**$0.11885**
106	A-5 TOU/Sec	Wntr	Mid-Pk $/kW & /kWh		$0.03300	$0.03761	$0.01729	**$0.08790**
107	A-5 TOU/Sec	Wntr	Off-Pk $/kW & /kWh		$0.03300	$0.02421	$0.01729	**$0.07450**
108								
109	A-5 TOU/Pri	Sumr	Fixed Charges					
110	A-5 TOU/Pri	Sumr	Max Demand					
111	A-5 TOU/Pri	Sumr	FIRM On-Pk $/kW & /kWh	**$4.60**	$0.03300	$0.06657	$0.01729	**$0.11686**
112	A-5 TOU/Pri	Sumr	NON-FIRM On-Pk $/kW & /kWh	**$4.60**	$0.03300	$0.06657	$0.01729	**$0.11686**
113	A-5 TOU/Pri	Sumr	Mid-Pk $/kW & /kWh		$0.03300	$0.03632	$0.01729	**$0.08661**
114	A-5 TOU/Pri	Sumr	Off-Pk $/kW & /kWh		$0.03300	$0.02322	$0.01729	**$0.07351**
115	A-5 TOU/Pri	Wntr	Fixed Charges					
116	A-5 TOU/Pri	Wntr	Max Demand					
117	A-5 TOU/Pri	Wntr	FIRM On-Pk $/kW & /kWh	**$4.60**	$0.03300	$0.06657	$0.01729	**$0.11686**

Line #	Rate Schedule	Season	Tier / TOU	Supply Dem. Chrg. $/kW	Trans $/kWh	Supply $/kWh	Supply Adj. $/kWh	SUBTOTAL SAM Rates
118	A-5 TOU/Pri	Wntr	NON-FIRM On-Pk $/kW & /kWh	**$4.60**	$0.03300	$0.06657	$0.01729	**$0.11686**
119	A-5 TOU/Pri	Wntr	Mid-Pk $/kW & /kWh		$0.03300	$0.03632	$0.01729	**$0.08661**
120	A-5 TOU/Pri	Wntr	Off-Pk $/kW & /kWh		$0.03300	$0.02322	$0.01729	**$0.07351**
121								
122	**Street Lighting**							
123	SL	Sumr	Customer					
124	SL	Sumr	Facilities Charge/Lamp/day					
125	SL	Sumr	Energy Charge		$0.03300	$0.03631	$0.01729	**$0.08660**
126	SL	Wntr	Customer					
127	SL	Wntr	Facilities Charge					
128	SL	Wntr	Energy Charge		$0.03300	$0.03631	$0.01729	**$0.08660**

Exhibit J
PRELIMINARY STATEMENTS

L. SUPPLY ADJUSTMENT MECHANISM

1. The purpose of the Supply-Adjustment Mechanism is to recover in rates the costs related to the Transmission Charge and the Supply Charge, and to have the Supply Adjustment Charge be a charge or a credit when the balance in the Supply Adjustment Balancing Account reflects an under-collection or an over-collection, respectively.

2. The monthly charges for service otherwise applicable under each of the utility's rate schedules shall include: a) the Transmission Charge, b) the Supply Charge and c) the Supply Adjustment Charge. The Supply Charge and the Transmission Charge shall be expressed in terms of a cents-per-kilowatt-hour charge or a dollars-per-kilowatt charge depending upon the nature of the charge and the applicable rate schedule. The Supply Adjustment Charge shall be expressed in terms of a cents-per-kilowatt-hour charge or credit.

   a. The Transmission Charge shall be designed to recover the most recently adopted estimate of costs to the utility for California Independent System Operator Corporation services, transmission services, ancillary services, system protection services, capacity charges, all SCE transmission charges, option premiums, and schedule dispatch charges (collectively, Transmission Costs).
   b. The Supply Charge shall be designed to recover the most recently adopted estimate of the costs to the utility of purchasing electricity, fuel, renewable energy credits (RECs) and imbalance energy (collectively, Supply Costs).
   c. The Supply Adjustment Charge shall be designed to recover or return, respectively, any under-collection or over-collection balance in the Supply Adjustment Balancing Account.

3. A Supply Adjustment Balancing Account (Balancing Account) shall be maintained to record the difference between the accumulated billings of the Transmission Charge, the Supply Charge and the Supply Adjustment Charge, and the accumulated accruedTransmission Costs and Supply Costs. Monthly entries to the Balancing Account will be determined from the following calculations:

   a. Accumulated billings during the month from Transmission Charge, Supply Charge and Supply Adjustment Charge;
   b. Less the adjustment to reflect the current adopted rate for franchise fees and uncollectibles;
   c. Less accrued Transmission Costs;
   d. Less accrued Supply Costs;
   e. Plus any refunds for Supply Costs or Transmission Costs previously reflected in the Balancing Account;
   f. Plus or minus interest expense, depending upon whether there is an under-collection or over-collection in the Balancing Account; such interest shall be calculated based upon the average of the beginning and ending monthly balance in the Balancing Account multiplied by the 90-day commercial paper rate for the month;
   g. Less an adjustment, if any, for the direct payment of refunds to customers;
   h. Less any costs related to the purchase of RECs;
   i. Plus any proceeds from the sale of RECs;
   j. Less any power purchase payments provided to eligible Net Energy Metering customers for energy produced by on-site generation in excess of consumption over a 12-month period;. power purchase payments may include additional compensation for renewable attributes where applicable; and
   k. The accumulated accrual cost of Supply Costs shall be trued-up on a monthly basis.

If the above calculation produces a positive amount (over-collection), such amount shall be credited to the Balancing Account. If the calculation produces a negative amount (under-collection), such amount shall be debited to the Balancing Account.

4. The utility may make periodic advice letter filings to revise the Supply Adjustment Charge to reflect the most current status of the Balancing Account.

5. Not more often than once per year, the utility may file an application to revise the Transmission Charge and/or Supply Charge to recover in rates the most current estimates of its Transmission Costs and/or Supply Costs.

Exhibit K

Schedule SSC

SPECIAL SERVICE CHARGES

APPLICABILITY

Applicable to all customers.

TERRITORY

Big Bear Lake and vicinity, San Bernardino County.

RATES

	During Regular Business Hours	During Non-Business Hours
SERVICE ESTABLISHMENT AND RECONNECTION CHARGES:		
Regular (>24 hours advance notice)/Turn-on at panel	$15.00	N/A
Expedited (<24 hours advance notice)/Turn-on at panel	$30.00	$100.00
Reconnection at pole	$110.00	$110.00
TURN-OFF NOTICE (BY DOOR HANGER) CHARGE:		
Per Notice	$15.00	N/A
TEMPORARY SERVICE CONNECTION CHARGE (See Rule No. 13):		
Per Connection	$75.00	N/A
CLEAN AND SHOW CHARGE; (see Spec Cond #4):		
Regular (>24 hours advance notice)/Turn-on at panel	$25.00	N/A
Regular (<24 hours advance notice)/Turn-on at panel	$40.00	N/A
Expedited (same day or after hours)/Turn-on at panel	$110.00	$110.00
RETURN CHECK CHARGE		
Each check returned	$10.00	N/A

LATE PAYMENT CHARGE (all accounts except CARE):
If unpaid more than 50 days after each date a bill is rendered, 1% times unpaid balance.
(see Special Cond #5)

SPECIAL CONDITIONS

1. The applicable special charges provided for herein are in addition to the charges calculated in accordance with any applicable rate schedule. At the sole discretion of the utility, the collection of the special charges under this schedule may be waived.

2. The non-business hours (weekends, posted holidays, after 4:30 pm Monday thru Friday in the winter and after 3:30 pm Monday through Friday during the summer) rate is to be applied whenever the customer requests that electric service be turned on or reconnected outside regular business hours and within four hours after the request is received.

3. The turn-off notice charge may be charged whenever the utility is required to dispatch a serviceperson to hang a turn-off notice at a customer's premises for nonpayment.

4. Clean and Show is a temporary service (not to exceed three days) which may be used to allow the owner or landlord to prepare the premises for subsequent sale or rental. Dates for initiating and terminating the

service shall be established at the time this service is requested. The rate requires that the customer give not less than 24 hours advance notice to the utility and includes one connection and one disconnection, which shall be performed during normal business hours. If less than 24 hours notice is given to the utility, or if service is requested to begin the same day, after normal business hours or on weekends, then expedited service charges shall apply.

5. A late charge will be assessed for bills unpaid in excess of 50 days for all customers except those on the CARE program. For bill outstanding for more than 50 days, a charge of 1% per month will be assessed until payment is made. Interest charges will be added to the unpaid amount and must be paid before reconnection where service has been disconnected.

Exhibit K

Rule 9

A. Rendering of Bills

1. Metered Service. Bills for metered service will be based on meter registrations. Meters will be read as required for the preparation of regular bills, opening bills, and closing bills. It may not be possible always to read meters on the same day of the month or at intervals of equal numbers of days.

2. Service Period. Bills for electric service will normally be rendered on a monthly; except that BVES may render bills more or less frequently at the option of BVES.

3. Monthly Rate Schedules. Bills for accounts on rate schedules with monthly charges will normally be billed for a monthly period.

   a. Monthly Billing Period. A monthly billing period will contain 27 to 33 days.

      Bills for accounts which are normally billed for a monthly billing period, including accounts based on a measured monthly demand, will be calculated on a pro rata computation for other than a monthly billing period.

   b. Bimonthly Billing Period. A bimonthly billing period will contain 54 to 66 days.

   c. Pro Rata Computation. Where a pro rata computation is made, the billing will be computed in accordance with the applicable rate schedule, but the size of the energy blocks, and the amount of the monthly charges and credits specified therein, will be prorated on the basis of the ratio of the number of days in the billing period to the number of days in a monthly or bimonthly billing period. For this purpose, an average monthly or bimonthly billing period of 30 days or 60 days, respectively, may be used unless otherwise provided in the tariff schedules.

B. Reading of Separate Meters Not Combined. For the purpose of billing, each meter on the customer's premises will be considered separately, and the readings to two or more meters will not be combined except as follows:

1. Where combinations of meter readings are specifically provided for in the rate schedule.

2. Where BVES' operating convenience requires the use of more than one meter.

C. Payment of bills. All bills are due and payable on presentation, and payment should be made at BVES' office or to an authorized representative or agent. If payment is later, there may be a late fee (see paragraph D).

D. Late Payment Charge: BVES may impose late charges for unpaid past due bills.

Schedule "S" Standby

"Backup" or Standby Service When On-site Generation Is Unavailable

APPLICABILITY

Applicable to customers taking service under Schedule A-4 TOU and A5-TOU secondary (the customer's Otherwise Applicable Rate "OAT"), where a part or all of the electrical requirements of the customer can be supplied from a generating facility located on the customer's premises. The service provided on this Rate Schedule is for backup or breakdown service when the customer's generation is unavailable for any reason. A generating facility may be connected for: (1) parallel operation with the service of BVES; or (2) isolated operation with standby or breakdown service provided by BVES by means of a double throw switch.

Solar Customers who are taking service under the Utility's Net Energy Metering tariff are exempt from standby charges. Non solar customers taking service under BVES Net Energy Metering schedules may be exempt from standby charges pursuant to PU Code Section 2827. See Special Condition #1 "Exemptions".

TERRITORY

Within the entire territory served by BVES.

OVERVIEW OF RATES

Backup Service is applicable when customers request BVES to provide service during outages (for any reason) of the customer's generating facility. BVES is not providing "maintenance service" at this time. Except as provided under this Schedule, the charges, terms and conditions of the customer's OAT shall apply.

CHARGES FOR BACKUP SERVICE

Demand Charges (Generation & Transmission Only*) $/KW/month

Demand ($/KW)	Distribution	Transmission	Generation	Total
A-4 TOU	Minimum charge in A-4 TOU partially covers distribution	$2.50/KW-month	$8.00/KW-month	$10.50/KW-month
A-5 TOU Secondary	Minimum charge in A-5 TOU secondary partially covers distribution	$0.75/KW-month	$0.75/KW-month	$1.50/KW-month
A-5 TOU Primary	NA	NA	NA	NA

* Note: There is a distribution minimum charge included in the A-4 TOU and A-5 TOU tariffs although they only partially cover the distribution costs and are not a standby charge since they are based on the contract demand.
NA = Not Available at this time

STANDBY BILLING DEMAND (KW) CALCULATIONS

The Standby Demand (kW) used for determining the Demand Charge under this Schedule is based on the difference between the customer's OAT Demand as recorded by the meter used for their OAT and its Generator Demand as determined by one of the two options below.

A. Customers receiving service under this Schedule shall have the kW demand for each 15-minute interval in the applicable time period and season of the billing period determined under one of the two methods below:

1. For customers who do not have Net-Generation-Output (NGO) interval metering to record the kW output of the generation facility, the demand shall be the difference between the nameplate rating of the customer's onsite generation known as the Customer Generator Nameplate (CGN) (see Definitions) and the larger of either their metered Maximum On-peak or metered Maximum Mid-Peak Demand (kW) provided by their OAT meter. In this case, the Standby Charge is computed each month as follows:

Standby Charge = [(CGN) – (Max. OAT On-peak & Mid-peak Demand)] x Total Standby Rate ($/KW)

2. For customers with interval NGO metering installed to record the kW output of the generating facility, the Standby demand is equal to the demand measured by the NGO's metered maximum demand (kW) output of the generating facility within the on-peak and mid-peak periods, less the larger of either their metered maximum on-peak or metered maximum mid-peak demand (kW) from the OAT meter. In this case, the Standby Charge is computed each month as follows:

Standby Charge = [(Generator Maximum Demand from NGO) – (OAT Demand)] x Total Standby Rate ($/KW).

SPECIAL CONDITIONS

1. **Definitions**:
   a. **Standby Demand** is defined as the generation and transmission capacity needed by BVES to serve the customer's loads normally served by the customer's generating facility when such facility is not available for any reason. Standby Demand does not include a distribution component as that charge is already included in the customer's OAT. Standby Demand shall not exceed the nameplate capacity of the customer's generating facility or the level of the customer's Contract Demand.

   b. **Generator Demand** is defined as the output of the customer's generator measured or computed in KW from the customer's 15-minute metered interval, but, where applicable, not less that the diversified resistance welder load computed in accordance with the section designated Welder Service in Rule 2. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

   c. **OAT Demand** is defined as the higher of the on-peak or mid-peak metered demand values for those two periods.

   d. **Customer Generator Nameplate (CGN)** is defined as nameplate rating of all the onsite generator capacity normally used to serve as onsite generation rather than as standby emergency backup service.

   e. **OAT (Otherwise Applicable Tariff)** is defined as the regular Tariff Schedule that applies to the customer's service provided by BVES. The OATs to which this Standby rate apply include Schedule A-4 TOU and A-5 TOU secondary.

   f. **Backup Service** or **Standby Service** is defined as equipment and contractual arrangements for transmission and generation which are not directly used and charged through the customer's applicable OAT but are nevertheless completed, ready and waiting to serve the customer's needs for capacity and energy in the event the customer's generation is unavailable for any reason.

2. **Exemptions**:
   An exemption from the charges of this Schedule is applicable to:
   a. The portion of a customer's load that can normally be served by one or more net energy metered (NEM) eligible generators, defined herein as an electrical generator fueled by solar, wind, a hybrid of solar and wind, biogas, or fuel cell, where the total nameplate generating capacity of all NEM-eligible generators at a single premises does not exceed 1 MW. However, a generator fueled by biogas, may be exempt from this Schedule if the nameplate generating capacity is greater than 1 MW but no greater than 10 MW, and where such generator meets the provisions of Public Utilities Code Section 2827.9 (b)(2)(A&B).

   b. Customers who install generating facilities of the type and size and during the time periods specified in Commission Decision (D.) 03-04-060 that meet all other criteria in PU Code Section 353.1. Based on these conditions, the following shall apply to new and existing qualified customers. Customers who install generating facilities that are ultra clean resources, as defined in PU Code Section 353.2, sized 5 MW or smaller, installed and operational between January 1, 2003 and December 31, 2008 and that meet all other criteria in PU Code Section 353.1. Such customers shall receive service under their OAT through June 1, 2011.

3. **Agreements Required Under This Rate Schedule.**
   a. If the customer wishes to install NGO metering to replace the default use of the CGN value for computing the standby charge, an agreement with BVES is required.

   b. A generation interconnection agreement may be required for service under this Schedule for those customers operating in parallel, but not for those customers that interconnect through a double throw switch and who do not operate in parallel.

4. **Standby Service Is Not A Guarantee of Uninterrupted Service.**
   Standby Service is not a guarantee of uninterrupted electric service for two reasons:
   a. Under unusual or emergency conditions, any firm customer may find their service interrupted.

b. This Standby Service may be interrupted at the same time the customer OAT service is interrupted if the customer has elected an interruptible option under its OAT rate.

Rule 7
Cal. P.U.C Sheet No. 1879-E, D.10-10-032, AL 247-E
Deposits

A. Amount of Deposit. The amount of deposit required to establish or re-establish credit is twice the estimated average monthly bill as estimated by BVES, but in no case may the amount of deposit be less than $15.00. The amount of deposit required to establish or re-establish credit for a Small Business Customer, as defined in Rule 1, is twice the estimated maximum monthly bill as estimated by BVES, but in no case may the amount of deposit be less than $25.00.

B. Return of Deposit.

1. When an application for electric service has been canceled prior to the establishment of electric service, the deposit will be applied to any charges applicable in accordance with the tariff schedules and the excess portion of the deposit will be returned, and the applicant will be advised.

2. When the customer's credit may be otherwise established in accordance with Rule No. 6, BVES may refund the deposit either upon the customer's request for return of the deposit or upon review by BVES.

3. Upon discontinuance of electric service, BVES will refund the customer's deposit or the balance in excess of unpaid bills for service.

4. After the customer has paid bills for electric service without becoming past due, as prescribed in Rule No. 11, for twelve months, BVES will refund the deposit by applying it to the customer's account or by draft, provided that the customer's credit would, thereafter, be otherwise established under Rule No. 6.

5. Deposits cannot be used to offset past due bills to avoid or delay discontinuance of service.

C. Interest on Deposits.

1. Interest on deposits will be paid by BVES at the rate of 1/12 of the interest rate on Commercial Paper (prime, 3 months), published the prior month in the Federal Reserve Statistical Release, G.13. Should publication of the interest rate on Commercial Paper (prime, 3 months) be discontinued, interest will so accrue at the rate of 1/12 of the interest rate on Commercial Paper, which most closely approximates the discontinued rate, and which is published the prior month in the Federal Reserve Statistical Release, G.13, or its successor publication. Applicable interest commences on the date the deposit is received and earned interest will be paid at the time the deposit is applied to the customer's account or refunded.

2. No interest will be paid for periods covered by bills paid after becoming past due. No interest will be paid if service is temporarily or permanently discontinued for nonpayment of bills. No interest will be paid if a deposit is held less than full month increments.

Exhibit K
Rule 20

REPLACEMENT OF OVERHEAD WITH UNDERGROUND ELECTRIC FACILITIES

A. BVES will at its expense, replace its existing overhead electric facilities with underground electric facilities along public streets and roads, and on public lands and private property across which rights-of-ways satisfactory to BVES have been obtained by BVES, provided that:

1. The governing body of the city or county in which such electric facilities are and will be located has:

   a. Determined, after consultation with BVES and after holding public hearings on the subject, that such undergrounding is in the general public interest for one or more of the following reasons:

      (1) Such undergrounding will avoid or eliminate an unusually heavy concentration of overhead electric facilities;

      (2) The street, road or right-of-way is extensively used by the general public and carries a heavy volume of pedestrian or vehicular traffic;

      (3) The street, road or right-of-way adjoins or passes through a civic area or public recreation area or an area of unusual scenic interest to the general public; or

      (4) The street or road or right-of-way is considered an arterial street or major collector road, as defined in the Governor's Office of Planning and Research General Plan Guidelines.

   b. Adopted an ordinance creating an underground district in the area in which both the existing and new facilities are and will be located requiring, among other things, (1) that all existing overhead communication and electric distribution facilities in such district shall be removed, (2) that each property served from such electric overhead facilities shall have been installed in accordance with BVES' rules for underground service, all electrical facility changes on the premises necessary to receive service from the underground facilities of BVES as soon as it is available, and (3) authorizing BVES to discontinue its overhead service.

2. BVES' total annual budgeted amount for undergrounding within any city or the unincorporated area of any county shall be allocated as follows:

   a. The amount allocated to each city and county in 1990 shall be the highest of:

      (1) The amount allocated to the city or county in 1989, which amount shall be allocated in the same ratio that the number of overhead meters in such city or unincorporated area of any county bears to the total system overhead meters; or

      (2) The amount the city or county would receive if BVES' total annual budgeted amount for undergrounding provided in 1989 were allocated in the same ratio that the number of overhead meters in each city or the unincorporated area of each county bears to the total system overhead meters based on the latest count of overhead meters available prior to establishing the 1990 allocations; or

(3) The amount the city or county would receive if BVES' total annual budgeted amount for undergrounding provided in 1989 were allocated as follows:

(a) Fifty percent of the budgeted amount allocated in the same ratio that the number of overhead meters in any city or the unincorporated area of any county bears to the total system overhead meters; and

(b) Fifty percent of the budgeted amount allocated in the same ratio that the total number of meters in any city or the unincorporated area of any county bears to the total system meters.

b. Except as provided in Section 2.c., the amount allocated for undergrounding within any city or the unincorporated area of any county in 1991 and later years shall use the amount actually allocated to the city or county in 1990 as the base, and any changes from the 1990 level in BVES' total annual budgeted amount for undergrounding shall be allocated to the individual cities and countries as follows:

(1) Fifty percent of the change from the 1990 total budgeted amount shall be allocated in the same ratio that the number of overhead meters in any city or unincorporated area of any county bears to the total system overhead meters.

(2) Fifty percent of the change from the 1990 total budgeted amount shall be allocated in the same ratio that the total number of meters in any city or the unincorporated area of any county bears to the total system meters.

c. When a city incorporates, resulting in a transfer of utility meters from the unincorporated area of a county to the city, there shall be a permanent transfer of a pro rata portion of the county's 1990 allocation base referred to in Section 2.b. to the city. The amount transferred shall be determined:

(1) Fifty percent based on the ratio that the number of overhead meters in the city bears to the total system overhead meters; and

(2) Fifty percent based on the ratio that the total number of meters in the city bears to the total system meters.

When the territory is annexed to an existed city, it shall be the responsibility of the city and county affected, in consultation with BVES serving the territory, to agree upon an amount of the 1990 allocation base that will be transferred from the county to the city, and thereafter to jointly notify BVES in writing.

d. However, Section 2 a, b, and c shall not apply to any utility where the total amount available for allocation under Rule 20-A is equal to or greater than 1.5 times the previous year's statewide average on a per customer basis. In such cases, BVES' total annual budgeted amount for undergrounding within any city or the unincorporated area of any county shall be allocated in the same ratio that the number of overhead meters in the city or unincorporated area of the county bears to the total system overhead meters.

e. Upon request by a city or county, the amounts allocated in accordance with Section 2. a, b, c, or d may be exceeded for each city or county by an amount up to a maximum of five years' allocation at then-current levels may be exceeded where BVES establishes that additional participation on a project is warranted and resources are available. Such allocated amounts may be carried over for a reasonable period of time in communities with active undergrounding programs. In order to qualify as a community with an active under-grounding program, the governing body must have adopted an ordinance or ordinances creating an underground district and/or districts as set forth in Section A.1.b. of this Rule. Where there is a carry-over or additional requested participation as discussed above, BVES has the right to set, as determined by its capability, reasonable limits on the rate of performance of the work to be financed by the funds carried over. When amounts are not expended or carried over for the community to which they are initially allocated, they shall be assigned when additional participation on a project is warranted or be reallocated to communities with active undergrounding programs.

3. The undergrounding extends for a minimum distance of one block or 600 feet, whichever is the lesser. Upon request of the governing body, BVES will pay from the existing allocation of that entity for:

   a. The installation of no more than 100 feet of each customer's underground electric service lateral occasioned by the undergrounding, and/or

   b. The conversion of a customer's meter panel to accept underground service occasioned by the undergrounding, excluding permit fees.

   BVES or the governing body may establish a lesser allowance, or may otherwise limit the amount of money to be expended on a single customer's electric service, or the total amount to be expended on all electric service installations in a particular project.

B. In circumstances other than those covered by A above, BVES will replace its existing overhead electric facilities with underground electric facilities along public streets and roads or other locations mutually agreed-upon when requested by an applicant or applicants when all of the following conditions are met:

1 a. All property owners served from the overhead facilities to be removed first agree in writing to have the wiring changes made on their premises so that service may be furnished from the underground distribution system in accordance with BVES' rules and that BVES may discontinue its overhead service upon completion of the underground facilities, or

   b. Suitable legislation is in effect requiring such necessary wiring changes to be made and authorizing BVES to discontinue its overhead service.

2. The applicant has:
   a. Furnished and installed the pads and vaults for transformers and associated equipment, conduits, ducts, boxes, pole bases and performed other work related to structures and substructures including breaking of pavement, trenching, backfilling, and repaving required in connection with the installation of the underground system, all in accordance with BVES' specifications, or, in lieu thereof, paid BVES to do so;

   b. Transferred ownership of such facilities, in good condition, to BVES; and

   c. Paid a nonrefundable sum equal to the excess, if any, of the estimated costs, including transformers, meters, and services, of completing the underground system and building a new equivalent overhead system. The cost of removal of the overhead poles, lines, and facilities are the responsibility of BVES and will be paid by BVES. Such payments shall not operate to reduce Rule 20.A allocations.

3. The area to be undergrounded includes both sides of a street for at least one block or 600 feet, whichever is the lesser, and all existing overhead communication and electric distribution facilities within the area will be removed.

4. BVES may, when requested and authorized by the city or county and mutually agreed-upon by such government entity and BVES, initially fund any required engineering/design costs for conversion projects under this section. In the event such a project proceeds, the requesting city or county shall reimburse BVES for such engineering/design costs before BVES shall be required to commence further work on the project. In the event the project is not approved to proceed within two and one half years of BVES's delivery of such engineering/design study, the requesting city or county shall reimburse BVES for its costs of such engineering/design study within 90 days of a demand by BVES. In the event a city or county does not reimburse BVES within 90 days of its demand for reimbursement, BVES shall be permitted to expense such costs as an operational cost and shall reduce the city or county's allocations provided under Section A of this Schedule by the like amount.

C. In circumstances other than those covered by A or B above, when mutually agreed-upon by BVES and an applicant, overhead electric facilities may be replaced with underground electric facilities, provided the applicant requesting the changes pays, in advance, a nonrefundable sum equal to the estimated cost of the underground facilities less the estimated net salvage value and depreciation of the replaced overhead facilities. Underground services will be installed and maintained as provided in BVES' rules applicable thereto.

D. The term "underground electric system" means an electric system with all wires installed underground, except those wires in surface mounted equipment enclosures.

(END OF APPENDIX A)

Exhibit K

Appendix B
Cost Allocation and Residential Customer Rate Design Settlement Agreement

Exhibit K

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

In the Matter of the Application of Golden State Water Company, on behalf of its Bear Valley Electric Service Division (U 913 E), for Approval of Costs and Authority to Increase General Rates and Other Charges for Electric Service by its Bear Valley Electric Service Division	Application No. 12-02-013 (Filed February 16, 2012)

COST ALLOCATION AND RESIDENTIAL CUSTOMER RATE DESIGN

SETTLEMENT AGREEMENT

12. INTRODUCTION

12.1. In accordance with Rule 12.1(a) of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure ("Rules"), the Settling Parties (as defined in section 2 below) enter into this Cost Allocation and Residential Customer Rate Design Settlement Agreement ("Settlement") for purposes of resolving certain matters in this proceeding, as specifically described herein.

12.2. The attached Joint Motion for Commission Approval and Adoption of Cost Allocation and Residential Customer Design Settlement Agreement ("Joint Motion") sets forth the factual and legal bases of the Settlement; advises the Commission of its scope; and presents the grounds on which Commission approval and adoption are urged.

12.3. As the Joint Motion explains, the Settlement complies with Commission requirements for approval of settlements because it is reasonable in light of the whole record, consistent with the law, and in the public interest. Accordingly, the Settling Parties respectfully urge the Commission to adopt and approve this Settlement.

12.4. The Settling Parties are entering into this Settlement to avoid the uncertainty of a Commission decision and to expedite Commission approval of provisions and tariffs consistent with this Settlement.

12.5. Since this Settlement represents a compromise, the Settling Parties have entered into each component of this Settlement on the basis that its approval by the Commission not be construed as an admission or concession by any Settling Party regarding any fact or matter of law in dispute in this proceeding or in any other proceeding before the Commission. Furthermore, the Settling Parties intend that the approval of this Settlement by the Commission not be construed as a precedent or statement of policy of any kind for or against any Settling Party in any current or future proceeding.

12.6. The issues among and between the Settling Parties that have been resolved through this Settlement are:

12.6.1. Cost allocation among customer classes (*i.e.*, how to allocate the overall revenue requirement among customer classes); and

12.6.2. Rate design principles for residential customers.

12.7. In a different, separate and uncontested settlement agreement entered into by the Settling Parties and ORA ("Revenue Requirement Settlement"),[42] all issues in this proceeding were resolved *except* cost allocation and rate design principles for residential customers. Without a resolution of the issues of cost allocation and rate design principles for residential customers, no final base rates could be determined.

12.8. If the Commission approves the Revenue Requirement Settlement and this Settlement, inputting the agreed-upon revenue requirements, cost allocation, and rate designs from both Settlements into BVES' rate model would yield final 2013 base rates for all BVES customers, as set forth in Section 4.7 of this Settlement.

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[42] All parties in this proceeding executed the Revenue Requirement Settlement (except Southern California Edison, who does not oppose approval of the Revenue Requirement Settlement). Thus, the Revenue Requirement Settlement is uncontested. All parties in this proceeding executed this Settlement except ORA and Southern California Edison. ORA contest this Settlement, while Southern California Edison does not oppose approval of this Settlement.

12.9. The GRC application in this proceeding was for Test Year 2013. Much of the record in this proceeding is in terms of the 2013 revenue requirement. Most of the figures cited in this Settlement are expressed in terms of 2013 costs and revenue requirements.

12.10. The Revenue Requirement Settlement includes a procedure to adjust the 2013 base rates, by customer class, to reflect agreed-upon post test-year increases in base rates for 2014, 2015, and 2016. The Settling Parties agree that the proposed 2013 base rates agreed-upon in Section 4.7 of this Settlement should be adjusted, using the procedure agreed-upon in the Revenue Requirement Settlement, to create the base rates for 2014, 2015, and 2016.

12.11. The Settling Parties anticipate that the Commission will issue a final decision in this proceeding prior to December 31, 2014. The Settling Parties agree that new 2014 rates should go into effect the date the Commission issues a final decision granting the Settlement Approval Motion and approving the Settlement.

13. DEFINITIONS

13.1. The term "BVES" means Bear Valley Electric Service (U 913-E), a division of Golden State Water Company, the applicant in this proceeding.

13.2. The term "ORA" means the Office of Ratepayer Advocates.[43]

13.3. The term "Snow Summit" means Snow Summit, Inc.

13.4. The term "City" means the City of Big Bear Lake, California.

13.5. The term "BBARWA" means the Big Bear Area Regional Wastewater Agency.

13.6. The term "Settling Parties" means collectively BVES, Snow Summit, the City, and BBARWA.

14. ATTACHMENTS

14.1. The following exhibits are attached to, and made a part of, this Settlement.

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[43] The Division of Ratepayer Advocates was renamed the Office of Ratepayer Advocates effective September 26, 2013. Although during the bulk of this proceeding references were made to the Division of Ratepayer Advocates or "DRA," for purposes of this Settlement, all references shall be to the Office of Ratepayer Advocates or "ORA."

14.1.1. Exhibit A: BVES Revenues by Component (as agreed-upon in Revenue Requirement Settlement) and System Average Rate Change Test Year 2013 (as agreed-upon in Revenue Requirement Settlement).

14.1.2. Exhibit B: Forecasted Sales by Revenue Class and Rate Class, Customer Counts and Miscellaneous Revenues at Present Rates (as agreed-upon in Revenue Requirement Settlement).

14.1.3. Exhibit C: Total Proposed Settlement Rates for 2013 (base rates only)

14.1.4. Exhibit D: Total Proposed Settlement Rates for 2013 (including base and supply rates)

15. TERMS AND CONDITIONS REGARDING MARGINAL COST ALLOCATIONS

Except as otherwise noted, the litigation amounts or positions of a party set forth below are consistent with those reflected in the Joint Comparison Exhibit accepted into the record in this proceeding as Exhibit JC-1, and attached as Appendix A to the Joint Motion.

15.1. Revenue Allocation Based Upon 20% Equal Percentage of Marginal Costs (EPMC) and 80% System Average Percentage Changes.

BVES originally recommended allocating revenues to customer classes using a two-part allocation approach: 10% based on equal percentage of marginal cost ("EPMC") and 90% based on system average percentage change ("SAPC"). One goal of the BVES proposal was to keep the rate increase for permanent residential customers below 11%. In its rebuttal testimony, BVES made certain changes to its original calculation of marginal costs and proposed base rate revenues, and recommended allocating revenues based on 7.5% use of EPMC and 92.5% use of SAPC. BVES made this change to its revenue allocation recommendation in order to meet the goal of keeping rate increases for permanent residential customers below 11%. Snow Summit recommended revenue allocation based on 50% use of EPMC and 50% use of SAPC, which would be phased in two steps: 25% use of EPMC initially and then an additional 25% use of EPMC timed with the expected removal of the Supply Adjustment Charge surcharge, which BVES estimated would occur in September 2014. ORA recommended allocating revenues based on 3.33% use of EPMC and 96.7% use of SAPC. The Settling Parties agree to revenue allocation for this proceeding based on 20% use of EPMC and 80% use of SAPC.

Allocation of Change in BVES 2013 Revenue Requirements[44]
by Customer Class under Different Allocation Assumptions

Customer Class	100% SAPC	100% EPMC	Settlement Revenue Allocation
Residential Total	$658,452	$2,982,889	$1,123,339
A-1	$143,493	($64,907)	$101,813
A-2	$96,410	($111,754)	$54,777
A-3	$119,712	($789,855)	($62,202)
A4-TOU	$70,891	($350,890)	($13,465)
Total Commercial	$430,506	($1,317,406)	$80,924
A5- secondary	$4,511	$61,704	$15,950
A5-primary	$66,838	($575,714)	($61,672)
Total Large Power	$71,350	($514,010)	($45,722)
Streetlights	$3,816	$12,651	$5,583
Total	$1,164,124	$1,164,124	$1,164,124

This revenue allocation keeps the revenue percent increase for permanent residential customers below 11%, as demonstrated in Section 4.5 below. This result is consistent with BVES' original goal for revenue allocation.

15.2. ***2013 Base Rate Revenue Requirements Agreed to in Revenue Requirement Settlement.*** In the Revenue Requirement Settlement, it was agreed by the Settling Parties and ORA that the overall base rate revenue requirement for Test Year 2013 would be $19,700,000. The Revenue Requirement Settlement also includes tables summarizing the agreed-upon key components of BVES' 2013 revenues by components and the system average rate change for Test Year 2013, described in Exhibit A attached hereto.

15.3. ***Sales, Customer Counts and Miscellaneous Revenue Forecasts Adopted in Revenue Requirement Settlement.*** The Revenue Requirement Settlement includes

44 Excludes Other Operating Revenue (OOR) and Standby revenue.

forecasts regarding BVES sales, customer counts by revenue class and rate class, and miscellaneous revenues at present rates as described Exhibit B, attached hereto.

15.4. ***BVES 2013 Revenue and System Average Rates.*** The Settling Parties agree to the summary of 2013 revenues and system average rates as set forth in the table below.

BVES 2013 Revenue and System Average Rates

Revenue Component	Revenue	System Average Rate (SAR)
Total Electric Base Rate Revenue[45]	$19,772,663	$0.141836
Total Supply Rate Revenue[46]	$17,297,600	$0.124082
Surcharge Revenue[47]	$3,387,538	$0.024300
Total Electric Revenue & SAR[48]	**$40,457,801**	**$0.290218**
Increase In Revenue[49]	**$1,301,611**	**$0.009337**
Deduct non-commodity revenues increases[50]	($137,488)	($0.000986)
Net Proposed SAR Change	**$1,164,124**	**$0.008351**
Proposed Rate SAR	**$41,621,925**	**$0.298569**
Increase to the Average Electric Rate		**2.88%**

15.5. ***BVES 2013 Change in Revenue Requirements Allocated by Customer Class*.** The Settling Parties agree to the 2013 system average rate change presented above and the allocation of the change in revenue requirements by customer class as set forth in the table below.

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[45] Total electric base rate revenue at present rates. Includes base adjustment revenue but excludes OOR since OOR is not a revenue from the sale of electricity.

[46] Total electric supply rate revenue at present rates. Includes supply adjustment revenue and an increase for Renewable Energy Credits in 2012.

[47] Includes the PPPC, CEMA and RPS surcharge revenues.

[48] Total present rate revenue.

[49] Includes a base rate revenue requirement reduction of $1.39 million plus $2.70 million in increases to offset revenue losses from reduced sales.

[50] Includes OOR and standby revenue.

BVES 2013 Change in Base Revenue Requirements Allocated by Customer Class Based on Settlement

Customer Class	Change in Net Revenues for Each Customer Class	Resulting Revenue Increase for Each Customer Class
Res Perm	$533,143	4.93%
Res Seas	$590,196	4.93%
Residential Total	$1,123,339	4.93%
A-1	$101,813	2.05%
A-2	$54,777	1.63%
A-3	($62,202)	-1.53%
A4-TOU	($13,465)	-0.56%
Total Commercial	$80,924	0.55%
A5- secondary	$15,950	9.47%
A5-primary	($61,672)	-2.39%
Total Large Power	($45,722)	-1.66%
Streetlights	$5,583	4.75%
Total or Average	**$1,164,124**	**2.88%**

The calculation of the revenue allocation to all customer classes based on 20% EPMC and 80% SAPC uses the BVES marginal cost model included in BVES' rebuttal testimony (Exhibit BVES-24 and summarized in Exhibit BVES-23). As summarized in the table above, the increase in revenue requirement based on the Revenue Requirement Settlement totals $1,164,124, which results in an average increase of 2.88% (which is equal to the Net Proposed SAR Change). The allocated increase in net revenues to residential customers uses an overall allocation of $1,123,339 in additional costs to all residential customers, based on a 20% movement to EPMC-based revenue allocation. The total residential allocation of $1,123,339 is divided between seasonal residential customers and non-seasonal residential customers in a manner that yields an equal percentage increase in current revenues for both permanent and seasonal residential customer classes. The cost allocation and resulting rates set forth in this Settlement utilize revenue requirements and other related information contained in the Revenue Requirement Settlement and set forth in Exhibits A, B, C, and D attached hereto.

4.6 ***Residential Rate Design Principles***. The table below summarizes the Settling Parties' residential rate design principles and the resulting rates:

Residential Rate Design Principles and Rates

Rate	Component	Current		BVES Rebuttal		Settlement	
		Values	% Change in Tiers	Values	% Change in Tiers	Values	% Change in Tiers
D*	Minimum charge per day (currently called service charge)	$0.2100		$0.33		$0.33	
	Tier 1 - Base line 315 kWh ($/kWh)	$0.0621		$0.1058		$0.08556	
	Tier 2 - 30% over baseline ($/kWh)	$0.0810	30.5%	$0.1182	11.7%	$0.11176	30.6%
	Tier 3 - all use above 2 ($/kWh)	$0.0973	20.1%	$0.1263	6.9%	$0.12414	11.1%
DMS	Multi family sub metered				Increase discount from $0.044/day to $0.10/day. **	Increase discount from $0.044/day to $0.10/day. **	
DO	Minimum charge per day	$0.85		$0.85		$0.85	
	Base Energy ($/kWh)	0.1427		$0.18661		$0.17240	
	Service Charge ($/day)	$0.21		$0.21		$0.21	

Minimum Charges: There are no changes in current tariff language except permanent residential: A minimum charge applied to the calculation of the total bill will be assessed when the sum of the standard energy, transmission, and supply charges is less than the specified Minimum Charge. This change eliminates surcharges in the minimum bill calculation.
* All other D-related rates including DM, DMS, and DE are a function of the D rate.
** The increase in the DMS discount reduces the bill impact on this customer group from the increase in the minimum charge.

Currently, permanent residential tier 2 rates are 30.5% above tier 1 rates, and tier 3 rates are 20.05% above tier 2 rates. BVES had proposed to reduce the increases in tiers 2 and 3 as noted in the above table (BVES Rebuttal). The Settling parties agree to increase the permanent residential tier 2 rates by 30.6% and permanent residential tier 3 rates by 11.1% in order to reduce bill impacts on customers with an average level of consumption of 450 kWh per month.

4.7 ***Final Base Rates for Test Year 2013.*** Based upon the agreements reached in the Revenue Requirement Settlement and this Settlement, the Settling Parties request the Commission adopt the 2013 base rates set forth in Exhibit C. These 2013 rates are based on (i) the overall 2013 base revenue requirement of $19,700,000 and rates and tariffs (including other operating revenues) agreed to in the Revenue Requirement Settlement,

(ii) the non-residential rate design principles agreed to in the Revenue Requirement Settlement, (iii) the cost allocation based on 80% SAPC and 20% EPMC agreed to in this Settlement, and (iv) the residential rate design principles agreed to in this Settlement Agreement.

4.8 ***Final Total Rates for Test Year 2013.*** Total 2013 rates are determined by adding the base rates and charges as described in 4.7 above and the supply rates and supply demand charges which were included in the Revenue Requirement Settlement. Exhibit D provides the 2013 rates that include the base rates, supply rates, and supply demand charges.

16. FURTHER ACTIONS.

The Settling Parties acknowledge that this Settlement is subject to approval by the Commission. As soon as practicable after all the Settling Parties have signed the Settlement, the Settling Parties through their respective attorneys will prepare and file the Joint Motion. The Settling Parties will furnish such additional information, documents, or testimonies as the Commission may require for purposes of granting the Joint Settlement and approving and adopting the Settlement.

16.1. ***No Personal Liability.*** None of the Settling Parties, or their respective employees, attorneys, or any other individual representative or agent, assumes any personal liability as a result of the Settling Parties executing this Settlement.

16.2. ***Non-Severability***. The provisions of this Settlement are non-severable. If any of the Settling Parties fails to perform its respective obligations under this Settlement, the Settlement will be regarded as rescinded.

16.3. ***Voluntary and Knowing Acceptance***. Each Settling Party hereto acknowledges and stipulates that it is agreeing to this Settlement freely, voluntarily, and without any fraud, duress, or undue influence by any other Settling Party. Each Settling Party has read and fully understands its rights, privileges, and duties under this Settlement, including its right to discuss this Settlement with its legal counsel, which has been exercised to the extent deemed necessary.

16.4. ***No Modification.*** This Settlement constitutes the entire Settlement among the Settling Parties regarding the matters set forth herein, which may not be altered, amended, or modified in any respect except in writing and with the express written and signed consent of all the Settling Parties hereto. All prior settlements, agreements, or other understandings, whether oral or in writing, regarding the matters set forth in this Settlement are expressly waived and have no further force or effect.

16.5. ***No Reliance.*** None of the Settling Parties has relied or presently relies on any statement, promise, or representation by any other Settling Party, whether oral or written, except as specifically set forth in this Settlement. Each Settling Party expressly assumes the risk of any mistake of law or fact made by such Settling Party or its authorized representative.

16.6. ***Counterparts.*** This Settlement may be executed in separate counterparts by the different Settling Parties hereto and all so executed will be binding and have the same effect as if all the Settling Parties had signed one and the same document. All such counterparts will be deemed to be an original and together constitute one and the same Settlement, notwithstanding that the signatures of all the Settling Parties and/or of a Settling Party's attorney or other representative do not appear on the same page of this Settlement or the related Joint Motion.

16.7. ***Binding upon Full Execution***. This Settlement will become effective and binding on each of the Settling Parties as of the date when it is fully executed. It will also be binding upon each of the Settling Parties' respective successors, subsidiaries, affiliates, representatives, agents, officers, directors, employees, and personal representatives, whether past, present, or future.

16.8. ***Commission Adoption Not Precedential.*** In accordance with Rule 12.5, the Settling Parties agree and acknowledge that unless the Commission expressly provides otherwise, its adoption of this Settlement does not constitute approval of or precedent regarding any principle or issue of law or fact in this or any other current or future proceeding.

16.9. ***Enforceability.*** The Settling Parties agree and acknowledge that after issuance of a Commission decision approving and adopting this Settlement, the Commission may reassert jurisdiction and reopen this proceeding to enforce the terms and conditions of this Settlement.

16.10. ***Finality.*** Once fully executed by the Settling Parties and adopted and approved by a Commission decision, this Settlement fully and finally settles any and all disputes among and between the Settling Parties in this proceeding, unless otherwise specifically provided in the Settlement.

16.11. ***No Admission.*** Nothing in this Settlement or related negotiations may be construed as an admission of any law or fact by any of the Settling Parties, or as precedential or binding on any of the Settling Parties in any other proceeding, whether before the Commission, in any court, or in any other state or federal administrative agency. Further, unless expressly stated herein, this Settlement does not constitute an acknowledgement, admission, or acceptance by any of the Settling Parties regarding any issue of law or fact in this matter, or the validity or invalidity of any particular method, theory, or principle of ratemaking or regulation in this or any other proceeding.

16.12. ***Authority to Sign.*** Each Settling Party who executes this Settlement represents and warrants to each other Settling Party that the individual signing this Settlement and the related Settlement Approval Motion has the legal authority to do so on behalf of the Settling Party.

16.13. ***Limited Admissibility***. Each Settling Party signing this Settlement agrees and acknowledges that this Settlement will be admissible in any subsequent Commission proceeding for the sole purpose of enforcing the terms and conditions of this Settlement.

16.14. ***Estoppel or Waiver.*** Unless expressly stated herein, the Settling Parties' execution of this Settlement is not intended to provide any of the Settling Parties in any manner a basis of estoppel or waiver in this or any other proceeding.

16.15. ***Rescission.*** If the Commission, any court, or any other state or federal administrative agency, rejects or materially alters any provision of the Settlement, it will be deemed rescinded by the Settling Parties and of no legal effect as of the date of issuance of the Commission decision or final ruling, decision, or modification by any court or any other state or federal administrative agency, rejecting or materially altering the Settlement. The Settling Parties may negotiate in good faith regarding whether they want to accept the changes by the Commission, any court, or any other state or federal administrative agency, and resubmit a revised Settlement to the Commission.

17. CONCLUSION

Each of the Settling Parties has executed this Settlement as of the date appearing below their respective signatures.

IN WITNESS WHEREOF, the Settling Parties have executed this Settlement as of May 7, 2014.

GOLDEN STATE WATER COMPANY,
On Behalf of its Bear Valley Electric Service Division

____

Title________________________
Date: __________

SNOW SUMMIT, INC.

____

Title ________________________
Date: __________

CITY OF BIG BEAR LAKE

____

Title ________________________
Date: __________

BIG BEAR AREA REGIONAL WASTEWATER AGENCY

____

Title ________________________
Date: __________

Exhibit A

Revenue Requirement Settlement Values

Table 1: BVES Revenues by Component
2013 in Millions

Component	BVES	ORA	Settlement
Total Present Rate Revenue	$40.69	$40.69	$40.69
Total Revenues Other Than Base Rate Rev	$22.29	$22.29	$22.29
Present Total Base Rate Revenues (excl Base Adj Revenue)	$18.40	$18.40	$18.40
Shortfall In Base Revenue To Authorized GO Allocation	$1.64	$1.64	$1.64
Shortfall in Base Revenue Due to Reduced Sales Forecast From Settlement	$1.05	$1.05	$1.05
2012 Authorized Base Revenue Requirement	$21.09	$21.09	$21.09
Proposed Increase to Reach 2013 Base Revenue Requirement	$1.00	($2.95)	($1.39)
Proposed 2013 Base Revenue Requirement	$22.10	$18.15	$19.70
Total Proposed Base Revenue Increase	$3.70	($0.25)	$1.30
Total Proposed Rate Revenue (incl OOR, Base Adj & Surcharges)	$44.39	$40.44	$41.99
Overall NET Revenue Increase	**9.09%**	**(0.62%)**	**3.20%**

Table 2: System Average Rate Change Test Year 2013

Electric Revenue & Rate Components	BVES		ORA		Settlement	
	Revenues	SAR $kWh	Revenues	SAR $kWh	Revenues	SAR $kWh
Total Electric Base Rate Revenue	$19,772,663	$0.141836	$19,772,663	$0.141836	$19,772,663	$0.141836
Total Supply Rate Revenue	$17,297,600	$0.124082	$17,297,600	$0.124082	$17,297,600	$0.124082
Surcharge Revenue	$3,696,989	$0.026520	$3,387,538	$0.024300	$3,387,538	$0.024300
Total Electric Sales Revenue & SAR	**$40,457,801**	**$0.290218**	**$40,457,801**	**$0.290218**	**$40,457,801**	**$0.290218**
Increase In Revenue	**$3,696,989**	**$0.026520**	**($224,714)**	**($0.001612)**	**$1,301,611**	**$0.009337**
Offset from Standby & Other Operating Income Increase	($137,488)	($0.000986)	($137,488)	($0.000986)	($137,488)	($0.000986)
Net Proposed SAR Change	$3,559,501	$0.025534	($362,202)	($0.002598)	$1,164,124	$0.008351
Proposed Rate SAR	**$44,017,302**	**$0.315752**	**$40,095,599**	**$0.287620**	**$41,621,925**	**$0.298569**
Increase to the Average Electric Rate	**8.80%**		**(0.90)%**		**2.88%**	

Exhibit A-1

Notes to Tables in Exhibit A

1. Table 1 ("BVES Revenues by Component 2013 in Millions") includes overall revenues, which include other operating revenues (OOR) and Standby revenue.
2. Table 2 ("System Average Rate Change Test Year 2013") includes only revenues that are a function of commodity sales, and thus it does not include OOR or Standby revenue.
3. The current Total Electric Sales Revenue of $40,457,801 million shown in the Settlement column in Table 2 is obtained from Table 1 as follows: $40.69 million Total Present Revenue minus $234,458 in OOR under present rates.
4. The Proposed Rate SAR of $41,621,925 shown in the Settlement column in Table 2 is obtained from Table 1 as follows: $41.99 million Total Proposed Revenue (incl OOR, Base Adj & Surcharges) minus $234,458 in OOR under present rates minus $137,488 proposed increase to OOR and Standby revenue.
5. Table 2 row headers are explained as follows:
   i. "Total Electric Base Rate Revenue" represents total electric base rate revenue at present rates. This includes base adjustment revenue but excludes OOR.
   ii. "Total Electric Supply Rate Revenue" represents total electric supply rate revenue at present rates. This Includes supply adjustment revenue and an increase for Renewable Energy Credits in 2012.
   iii. "Surcharge Revenue" includes the Public Purpose Charges ("PPPC"), Catastrophic Event Memo Account ("CEMA") and Renewable Portfolio Standard ("RPS") surcharge revenues.
   iv. "Total Electric Revenue & SAR" represents total present rate revenue.
   v. "Increase in Revenue" includes a base rate revenue requirement reduction of $1.39 million plus $2.70 million in increases to offset revenue losses from reduced sales.

Exhibit B
Revenue Requirement Settlement Values

2011 to 2016 Forecasted Sales by Revenue Class (kWh)

RATE CLASS	2011	2012	2013	2014	2015	2016
Residential	75,055,533	76,106,563	77,847,297	79,701,630	81,019,851	81,874,526
Commercial	44,021,458	45,389,468	48,335,524	51,693,766	53,543,857	54,285,642
Power	12,940,496	12,960,791	13,030,184	13,107,200	13,132,901	13,127,384
Street Lighting	191,852	191,852	191,852	191,852	191,852	191,852
Total	**132,209,339**	**134,648,674**	**139,404,857**	**144,694,448**	**147,888,461**	**149,479,404**

2010 - 2016 Customer Count by Revenue Class, Full-Time Equivalent

Component	2010 Recorded	2011 Estimated	2012 Estimated	2013 Estimated	2014 Estimated	2015 Estimated	2016 Estimated
Residential	21,349	21,503	21,635	21,762	21,890	22,019	22,151
Commercial	1,321	1,349	1,368	1,388	1,408	1,428	1,447
Power	4	4	4	4	4	4	4
Street Lighting	4	4	4	4	4	4	4
Total	**22,678**	**22,860**	**23,011**	**23,158**	**23,306**	**23,455**	**23,606**

2010 – 2016 Sales by Rate Class (KWh)

Rate Class	2010 Recorded	2011 Estimated	2012 Estimated	2013 Estimated	2014 Estimated	2015 Estimated	2016 Estimated
D (Sgl Fam Res "SFR")	31,094,251	29,894,938	30,216,708	30,855,891	31,567,734	32,008,028	32,196,417
DE (Employees SFRs)	297,204	288,524	297,392	310,241	322,085	332,551	340,535
NEM (Net Energy)	96,754	85,484	85,484	85,484	85,484	85,484	85,484
D-All Electric (SFRs)	69,769	147,618	150,114	144,318	151,056	142,784	142,133
D (Life Support SFRs)	791,471	1,583,883	1,727,451	1,884,733	2,048,551	2,214,442	2,381,966
DLI (Low Income	11,838,491	11,351,937	11,444,373	11,420,008	11,350,566	11,412,105	11,538,900
DM (Master Metered)	180,411	167,610	173,202	170,496	171,430	167,477	163,742
DMS (Submetered)	2,184,058	2,184,089	2,249,509	2,323,376	2,399,569	2,467,275	2,528,960
Perm Residential	**46,552,409**	**45,704,083**	**46,344,233**	**47,194,547**	**48,096,475**	**48,830,146**	**49,378,137**
Seasonal DO	29,586,663	29,351,450	29,762,330	30,652,750	31,605,155	32,189,705	32,496,389
Res Subtotal	**76,139,072**	**75,055,533**	**76,106,563**	**77,847,297**	**79,701,630**	**81,019,851**	**81,874,526**
A-1 Small (up to 20KW)	16,803,998	15,741,785	15,688,727	16,500,677	17,565,006	17,756,602	17,315,724
A-2 Medium (20-50KW)	10,233,005	10,148,320	10,693,519	11,582,105	12,566,747	13,233,076	13,663,504
A-3 Large (50-500KW)	12,269,003	11,151,470	11,736,233	12,452,538	13,192,720	13,863,791	14,448,042
A-4 TOU	5,100,050	6,844,653	7,135,759	7,664,974	8,234,063	8,555,158	8,723,142
Camp Oaks	137,185	135,230	135,230	135,230	135,230	135,230	135,230
Commercial	**44,543,241**	**44,021,458**	**45,389,468**	**48,335,524**	**51,693,766**	**53,543,857**	**54,285,642**
A-5 TOU sec	31,906	730,706	730,706	730,706	730,706	730,706	730,706
A5-TOU prim	11,297,884	12,209,790	12,230,085	12,299,478	12,376,494	12,402,195	12,396,678
Power	**11,329,790**	**12,940,496**	**12,960,791**	**13,030,184**	**13,107,200**	**13,132,901**	**13,127,384**
Street Ltg	**191,852**	**191,852**	**191,852**	**191,852**	**191,852**	**191,852**	**191,852**
TOTAL	**132,203,955**	**132,209,339**	**134,648,674**	**139,404,857**	**144,694,448**	**147,888,461**	**149,479,404**

Exhibit B

Miscellaneous Revenue at Present Rates 2011 to 2016

Category	2011	2012	2013	2014	2015	2016
Service Establishment	$39,705	$40,842	$41,978	$43,115	$44,251	$45,388
Reconnect Fees	$32,791	$34,292	$35,794	$37,295	$38,797	$40,298
Collection/Notice Fees	$56,824	$56,824	$56,824	$56,824	$56,824	$56,824
Temp Serve & Clean/Show	$3,901	$3,992	$4,083	$4,174	$4,264	$4,355
Return Check Fee	$0	$0	$0	$0	$0	$0
Late Payment Fee	$0	$0	$0	$0	$0	$0
Other Miscellaneous	$150	$150	$150	$150	$150	$150
Joint Pole	$95,629	$95,629	$95,629	$95,629	$95,629	$95,629
TOTAL	**$229,000**	**$231,729**	**$234,458**	**$237,186**	**$239,915**	**$242,644**

Exhibit C

Proposed Settlement Rates – 2013 Tariff Details
Base Rates Only -- Does not include Supply Portion of Rates[51]

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
	Permanent Residential											
1	D (Perm)	Sumr	Tier #1 Baseline (BL)	$0.000	$0.330		$0.08556	$0.01105	**$0.09661**	$0.02479	$0.00053	**$0.12193**
2	D (Perm)	Sumr	Tier #2 130% BL				$0.11176	$0.01105	**$0.12281**	$0.02479	$0.00053	**$0.14813**
3	D (Perm)	Sumr	Tier #3 All Other Use				$0.12414	$0.01105	**$0.13519**	$0.02479	$0.00053	**$0.16051**
4	D (Perm)	Wntr	Tier #1 Baseline (BL)	$0.000	$0.330		$0.08556	$0.01105	**$0.09661**	$0.02479	$0.00053	**$0.12193**
5	D (Perm)	Wntr	Tier #2 130% BL				$0.11176	$0.01105	**$0.12281**	$0.02479	$0.00053	**$0.14813**
6	D (Perm)	Wntr	Tier #3 All Other Use				$0.12414	$0.01105	**$0.13519**	$0.02479	$0.00053	**$0.16051**
7												
8	D (Employee)	Sumr	Tier #1 Baseline (BL)	$0.000	$0.330		$0.04278	$0.01105	**$0.05383**	$0.02479	$0.00053	**$0.07915**
9	D (Employee)	Sumr	Tier #2 130% BL				$0.05588	$0.01105	**$0.06693**	$0.02479	$0.00053	**$0.09225**
10	D (Employee)	Sumr	Tier #3 All Other Use				$0.06207	$0.01105	**$0.07312**	$0.02479	$0.00053	**$0.09844**
11	D (Employee)	Wntr	Tier #1 Baseline (BL)	$0.000	$0.330		$0.04278	$0.01105	**$0.05383**	$0.02479	$0.00053	**$0.07915**
12	D (Employee)	Wntr	Tier #2 130% BL				$0.05588	$0.01105	**$0.06693**	$0.02479	$0.00053	**$0.09225**
13	D (Employee)	Wntr	Tier #3 All Other Use				$0.06207	$0.01105	**$0.07312**	$0.02479	$0.00053	**$0.09844**
14												
15	D-LI (CARE)	Sumr	Tier #1 Baseline (BL)	$0.000	$0.264		$0.06845	$0.00884	**$0.07729**	$0.01408	$0.00053	**$0.09190**
16	D-LI (CARE)	Sumr	Tier #2 130% BL				$0.08941	$0.00884	**$0.09825**	$0.01408	$0.00053	**$0.11286**
17	D-LI (CARE)	Sumr	Tier #3 All Other Use				$0.09931	$0.00884	**$0.10815**	$0.01408	$0.00053	**$0.12276**
18	D-LI (CARE)	Wntr	Tier #1 Baseline (BL)	$0.000	$0.264		$0.06845	$0.00884	**$0.07729**	$0.01408	$0.00053	**$0.09190**
19	D-LI (CARE)	Wntr	Tier #2 130% BL				$0.08941	$0.00884	**$0.09825**	$0.01408	$0.00053	**$0.11286**
20	D-LI (CARE)	Wntr	Tier #3 All Other Use				$0.09931	$0.00884	**$0.10815**	$0.01408	$0.00053	**$0.12276**
21												
22	**Seasonal Residential**											
23	DO (Seas)	Sumr	Tier #1	$0.210	$0.850		$0.17240	$0.01105	**$0.18345**	$0.02479	$0.00053	**$0.20877**
24	DO (Seas)	Sumr	Tier #2				$0.17240	$0.01105	**$0.18345**	$0.02479	$0.00053	**$0.20877**
25	DO (Seas)	Wntr	Tier #1	$0.210	$0.850		$0.17240	$0.01105	**$0.18345**	$0.02479	$0.00053	**$0.20877**
26	DO (Seas)	Wntr	Tier #2				$0.17240	$0.01105	**$0.18345**	$0.02479	$0.00053	**$0.20877**
27												

51 Total rates are obtained by adding based rates included in this table and the uncontested supply rates included in Revenue Requirement settlement, as shown in Exhibit D.

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
28	**Master Metered Apartments (No Submeters)**											
29	DM (Perm)	Sumr	Tier #1 Baseline (BL)	$0.00000	$0.3300		$0.08556	$0.01105	**$0.09661**	$0.02479	$0.00053	**$0.12193**
30	DM (Perm)	Sumr	Tier #2 130% BL				$0.11176	$0.01105	**$0.12281**	$0.02479	$0.00053	**$0.14813**
31	DM (Perm)	Sumr	Tier #3 All Other Use				$0.12414	$0.01105	**$0.13519**	$0.02479	$0.00053	**$0.16051**
32	DM (Perm)	Wntr	Tier #1 Baseline (BL)	$0.00000	$0.330		$0.08556	$0.01105	**$0.09661**	$0.02479	$0.00053	**$0.12193**
33	DM (Perm)	Wntr	Tier #2 130% BL				$0.11176	$0.01105	**$0.12281**	$0.02479	$0.00053	**$0.14813**
34	DM (Perm)	Wntr	Tier #3 All Other Use				$0.12414	$0.01105	**$0.13519**	$0.02479	$0.00053	**$0.16051**
35												
36	**Master Metered Mobilehome Parks**											
37	DMS Meter	Sumr	Service Charge	**$0.000**			NA	NA	**NA**			**NA**
38	DMS Meter	Wntr	Service Charge	**$0.000**			NA	NA	**NA**			**NA**
39	DMS Meter	Sumr	Discount Per Occupied Unit	($0.100)			NA	NA	**NA**			**NA**
40	DMS Meter	Wntr	Discount Per Occupied Unit	($0.100)			NA	NA	**NA**			**NA**
41	*Apply to Submetered Acct Under DMS*											
42	D (Perm)	Sumr	Tier #1 Baseline (BL)	NA			$0.08556	$0.01105	**$0.09661**	$0.02479	$0.00053	**$0.12193**
43	D (Perm)	Sumr	Tier #2 130% BL				$0.11176	$0.01105	**$0.12281**	$0.02479	$0.00053	**$0.14813**
44	D (Perm)	Sumr	Tier #3 All Other Use				$0.12414	$0.01105	**$0.13519**	$0.02479	$0.00053	**$0.16051**
45	D (Perm)	Wntr	Tier #1 Baseline (BL)	NA			$0.08556	$0.01105	**$0.09661**	$0.02479	$0.00053	**$0.12193**
46	D (Perm)	Wntr	Tier #2 130% BL				$0.11176	$0.01105	**$0.12281**	$0.02479	$0.00053	**$0.14813**
47	D (Perm)	Wntr	Tier #3 All Other Use				$0.12414	$0.01105	**$0.13519**	$0.02479	$0.00053	**$0.16051**
48												
49	D-LI (Perm)	Sumr	Tier #1 Baseline (BL)	NA			$0.06845	$0.00884	**$0.07729**	$0.01408	$0.00053	**$0.09190**
50	D-LI (Perm)	Sumr	Tier #2 130% BL				$0.08941	$0.00884	**$0.09825**	$0.01408	$0.00053	**$0.11286**
51	D-LI (Perm)	Sumr	Tier #3 All Other Use				$0.09931	$0.00884	**$0.10815**	$0.01408	$0.00053	**$0.12276**
52	D-LI (Perm)	Wntr	Tier #1 Baseline (BL)	NA			$0.06845	$0.00884	**$0.07729**	$0.01408	$0.00053	**$0.09190**
53	D-LI (Perm)	Wntr	Tier #2 130% BL				$0.08941	$0.00884	**$0.09825**	$0.01408	$0.00053	**$0.11286**
54	D-LI (Perm)	Wntr	Tier #3 All Other Use				$0.09931	$0.00884	**$0.10815**	$0.01408	$0.00053	**$0.12276**
55												
56	DO (Seas)	Sumr	Tier #1				$0.17240	$0.01105	**$0.18345**	$0.02479	$0.00053	**$0.20877**
57	DO (Seas)	Sumr	Tier #2				$0.17240	$0.01105	**$0.18345**	$0.02479	$0.00053	**$0.20877**
58	DO (Seas)	Wntr	Tier #1				$0.17240	$0.01105	**$0.18345**	$0.02479	$0.00053	**$0.20877**
59	DO (Seas)	Wntr	Tier #2				$0.17240	$0.01105	**$0.18345**	$0.02479	$0.00053	**$0.20877**

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
60												
61	**Commercial (Small to Large)**											
62	A-1	Sumr	Tier #1	$0.45		$0.00	$0.13359	$0.01105	**$0.14464**	0.02479	0.00053	**$0.16996**
63	A-1	Sumr	Tier #2				$0.13359	$0.01105	**$0.14464**	0.02479	0.00053	**$0.16996**
64	A-1	Wntr	Tier #1	$0.45		$0.00	$0.13359	$0.01105	**$0.14464**	0.02479	0.00053	**$0.16996**
65	A-1	Wntr	Tier #2				$0.13359	$0.01105	**$0.14464**	0.02479	0.00053	**$0.16996**
66												
67	A-2	Sumr	Tier #1	$2.36			$0.13338	$0.01105	**$0.14443**	0.02479	0.00053	**$0.16975**
68	A-2	Sumr	Tier #2				$0.13338	$0.01105	**$0.14443**	0.02479	0.00053	**$0.16975**
69	A-2	Wntr	Tier #1	$2.36			$0.13338	$0.01105	**$0.14443**	0.02479	0.00053	**$0.16975**
70	A-2	Wntr	Tier #2				$0.13338	$0.01105	**$0.14443**	0.02479	0.00053	**$0.16975**
71												
72	A-3	Sumr	Demand			$9.00						
73	A-3	Sumr	Tier #1	$6.60			$0.11855	$0.01105	**$0.12960**	0.02479	0.00053	**$0.15492**
74	A-3	Sumr	Tier #2				$0.11855	$0.01105	**$0.12960**	0.02479	0.00053	**$0.15492**
75	A-3	Wntr	Demand			$9.00						
76	A-3	Wntr	Tier #1	$6.60			$0.11855	$0.01105	**$0.12960**	0.02479	0.00053	**$0.15492**
77	A-3	Wntr	Tier #2				$0.11855	$0.01105	**$0.12960**	0.02479	0.00053	**$0.15492**
78												
79	GSD	Sumr	Demand			$9.00						
80	GSD	Sumr	Tier #1	$0.23			$0.10000	$0.01105	**$0.11105**	0.02479	0.00053	**$0.13637**
81	GSD	Wntr	Demand			$9.00						
82	GSD	Wntr	Tier #1	$0.23			$0.11387	$0.01105	**$0.12492**	0.02479	0.00053	**$0.15024**
83												
84	**Very Large Customer Time-Of-Use**											
85	A-4 TOU	Sumr	Fixed Charges	$16.40	$3.00							
86	A-4 TOU	Sumr	Max Demand			$0.00						
87	A-4 TOU	Sumr	On-Pk $/kW & /kWh			$10.00	$0.11066	$0.01105	**$0.12171**	$0.02479	$0.00053	**$0.14703**
88	A-4 TOU	Sumr	Mid-Pk $/kW & /kWh				$0.11066	$0.01105	**$0.12171**	$0.02479	$0.00053	**$0.14703**
89	A-4 TOU	Sumr	Off-Pk $/kW & /kWh				$0.11066	$0.01105	**$0.12171**	$0.02479	$0.00053	**$0.14703**
90	A-4 TOU	Wntr	Fixed Charges	$16.40	$3.00							
91	A-4 TOU	Wntr	Max Demand			$0.00						
92	A-4 TOU	Wntr	On-Pk $/kW & /kWh			$10.00	$0.11066	$0.01105	**$0.12171**	$0.02479	$0.00053	**$0.14703**
93	A-4 TOU	Wntr	Mid-Pk $/kW & /kWh				$0.11066	$0.01105	**$0.12171**	$0.02479	$0.00053	**$0.14703**
94	A-4 TOU	Wntr	Off-Pk $/kW & /kWh				$0.11066	$0.01105	**$0.12171**	$0.02479	$0.00053	**$0.14703**
95												
96	A-5 TOU/Sec	Sumr	Fixed Charges	$65.80	$1.50							
97	A-5 TOU/Sec	Sumr	Max Demand			$4.30						
98	A-5 TOU/Sec	Sumr	FIRM BASE On-Pk $/kW & /kWh			$12.38	$0.04760	$0.01105	**$0.05865**	$0.02479	$0.00053	**$0.08397**
99	A-5 TOU/Sec	Sumr	NON-FIRM BASE On-Pk $/kW & /kWh			$7.00	$0.04760	$0.01105	**$0.05865**	$0.02479	$0.00053	**$0.08397**
100	A-5 TOU/Sec	Sumr	Mid-Pk $//kW & /kWh			$3.50	$0.04760	$0.01105	**$0.05865**	$0.02479	$0.00053	**$0.08397**
101	A-5 TOU/Sec	Sumr	Off-Pk $/kW & /kWh				$0.04760	$0.01105	**$0.05865**	$0.02479	$0.00053	**$0.08397**

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
102	A-5 TOU/Sec	Wntr	Fixed Charges	$65.80	$1.50							
103	A-5 TOU/Sec	Wntr	Max Demand			$4.30						
104	A-5 TOU/Sec	Wntr	FIRM BASE On-Pk $//kW & /kWh			$12.38	$0.04760	$0.01105	**$0.05865**	$0.02479	$0.00053	**$0.08397**
105	A-5 TOU/Sec	Wntr	NON-FIRM BASE On-Pk $//kW & /kWh			$7.00	$0.04760	$0.01105	**$0.05865**	$0.02479	$0.00053	**$0.08397**
106	A-5 TOU/Sec	Wntr	Mid-Pk $//kW & /kWh			$3.50	$0.04760	$0.01105	**$0.05865**	$0.02479	$0.00053	**$0.08397**
107	A-5 TOU/Sec	Wntr	Off-Pk $//kW & /kWh				$0.04760	$0.01105	**$0.05865**	$0.02479	$0.00053	**$0.08397**
108												
109	A-5 TOU/Pri	Sumr	Fixed Charges	$65.80	$1.50							
110	A-5 TOU/Pri	Sumr	Max Demand			$4.30						
111	A-5 TOU/Pri	Sumr	FIRM BASE On-Pk $//kW & /kWh			$12.38	$0.01638	$0.01105	**$0.02743**	$0.02479	$0.00053	**$0.05275**
112	A-5 TOU/Pri	Sumr	NON-FIRM BASE On-Pk $//kW & /kWh			$6.00	$0.01638	$0.01105	**$0.02743**	$0.02479	$0.00053	**$0.05275**
113	A-5 TOU/Pri	Sumr	Mid-Pk $//kW & /kWh			$3.50	$0.01638	$0.01105	**$0.02743**	$0.02479	$0.00053	**$0.05275**
114	A-5 TOU/Pri	Sumr	Off-Pk $//kW & /kWh				$0.01638	$0.01105	**$0.02743**	$0.02479	$0.00053	**$0.05275**
115	A-5 TOU/Pri	Wntr	Fixed Charges	$65.80	$1.50							
116	A-5 TOU/Pri	Wntr	Max Demand			$4.30						
117	A-5 TOU/Pri	Wntr	FIRM BASE On-Pk $//kW & /kWh			$12.38	$0.01638	$0.01105	**$0.02743**	$0.02479	$0.00053	**$0.05275**
118	A-5 TOU/Pri	Wntr	NON-FIRM BASE On-Pk $//kW & /kWh			$6.00	$0.01638	$0.01105	**$0.02743**	$0.02479	$0.00053	**$0.05275**
119	A-5 TOU/Pri	Wntr	Mid-Pk $//kW & /kWh			$3.50	$0.01638	$0.01105	**$0.02743**	$0.02479	$0.00053	**$0.05275**
120	A-5 TOU/Pri	Wntr	Off-Pk $//kW & /kWh				$0.01638	$0.01105	**$0.02743**	$0.02479	$0.00053	**$0.05275**
121												
122	**Street Lighting**											
123	SL	Sumr	Customer	$0.21								
124	SL	Sumr	Facilities Charge/Lamp/ day	$0.4340								
125	SL	Sumr	Energy Charge				$0.13666	$0.01105	**$0.16306**	$0.02479	$0.00053	**$0.27498**
126	SL	Wntr	Customer	$0.21								
127	SL	Wntr	Facilities Charge	$0.434								
128	SL	Wntr	Energy Charge				$0.13666	$0.01105	**$0.16306**	$0.02479	$0.00053	**$0.27498**

Exhibit C

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a. *The "Base Energy Adjustment" is an estimate of the expected BRRAM surcharge. The actual, authorized BRRAM surcharges in effect at the time rates are authorized will be substituted for this placeholder value.

b. ** The "All Other Charges" consist of Public Purpose Charges, the Renewable Portfolio Standard surcharge, and the Catastrophic Event Memo Account surcharge. Supply charges are not included in these charges. Charges shown are an estimate of the expected charges. The actual "other" charges in effect at the time rates are authorized will be substituted for these placeholder values.

c. Residential Minimum Charge: A minimum charge ($ per day) is applied to the calculation of the total bill will be assessed when the sum of the Service Charge, Base Energy, Transmission Charge, Supply Charge is less than the specified Minimum Charge.

d. Non-Residential Minimum Charge: A minimum charge ($ per kW) is applied to the calculation of the total bill and will be assessed when the sum of the Base Energy, Base Adjustment, Transmission Charge, Energy Charge, Supply Adjustment Charge and all Demand charges is less than the specified Minimum Charge.

e. A-4 Minimum Charge: Will be equal to the Service Charge per meter, per day, plus $1.50 per kW times Contract Demand (New Special Condition 7). New Special Condition 7 indicates "Contract Demand: Is the demand determined, at BVES' option, by an engineering evaluation of the connected load."

Exhibit C

Total Proposed Settlement 2013 Rates

Includes Base Rates And Supply Rates[52]

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
Permanent Residential																	
1	D (Perm)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.33			$0.08556	$0.01105	$0.09661	$0.03300	$0.02307	$0.01729	$0.07336	$0.02479	$0.00053	$0.19529
2	D (Perm)	Sumr	Tier #2 130% BL					$0.11176	$0.01105	$0.12281	$0.03300	$0.04667	$0.01729	$0.09696	$0.02479	$0.00053	$0.24509
3	D (Perm)	Sumr	Tier #3 All Other Use					$0.12414	$0.01105	$0.13519	$0.03300	$0.13482	$0.01729	$0.18511	$0.02479	$0.00053	$0.34562
4	D (Perm)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.33			$0.08556	$0.01105	$0.09661	$0.03300	$0.02307	$0.01729	$0.07336	$0.02479	$0.00053	$0.19529
5	D (Perm)	Wntr	Tier #2 130% BL					$0.11176	$0.01105	$0.12281	$0.03300	$0.04667	$0.01729	$0.09696	$0.02479	$0.00053	$0.24509
6	D (Perm)	Wntr	Tier #3 All Other Use					$0.12414	$0.01105	$0.13519	$0.03300	$0.13482	$0.01729	$0.18511	$0.02479	$0.00053	$0.34562
7																	
8	D (Employee)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.33			$0.04278	$0.01105	$0.05383	$0.01650	$0.01154	$0.00865	$0.03668	$0.02479	$0.00053	$0.11583

52 The rates in this table include the base rates from Exhibit C and the uncontested supply rates as summarized in the Revenue Requirements Settlement.

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
9	D (Employee)	Sumr	Tier #2 130% BL					$0.05588	$0.01105	$0.06693	$0.01650	$0.02334	$0.00865	$0.04848	$0.02479	$0.00053	$0.14073
10	D (Employee)	Sumr	Tier #3 All Other Use					$0.06207	$0.01105	$0.07312	$0.01650	$0.06741	$0.00865	$0.09256	$0.02479	$0.00053	$0.19100
11	D (Employee)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.33			$0.04278	$0.01105	$0.05383	$0.01650	$0.01154	$0.00865	$0.03668	$0.02479	$0.00053	$0.11583
12	D (Employee)	Wntr	Tier #2 130% BL					$0.05588	$0.01105	$0.06693	$0.01650	$0.02334	$0.00865	$0.04848	$0.02479	$0.00053	$0.14073
13	D (Employee)	Wntr	Tier #3 All Other Use					$0.06207	$0.01105	$0.07312	$0.01650	$0.06741	$0.00865	$0.09256	$0.02479	$0.00053	$0.19100
14																	
15	D-LI (CARE)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.264			$0.06845	$0.00884	$0.07729	$0.02640	$0.01846	$0.01383	$0.05869	$0.01408	$0.00053	$0.15059
16	D-LI (CARE)	Sumr	Tier #2 130% BL					$0.08941	$0.00884	$0.09825	$0.02640	$0.03734	$0.01383	$0.07757	$0.01408	$0.00053	$0.19043
17	D-LI (CARE)	Sumr	Tier #3 All Other Use					$0.09931	$0.00884	$0.10815	$0.02640	$0.10786	$0.01383	$0.14809	$0.01408	$0.00053	$0.27085
18	D-LI (CARE)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.264			$0.06845	$0.00884	$0.07729	$0.02640	$0.01846	$0.01383	$0.05869	$0.01408	$0.00053	$0.15059
19	D-LI (CARE)	Wntr	Tier #2 130% BL					$0.08941	$0.00884	$0.09825	$0.02640	$0.03734	$0.01383	$0.07757	$0.01408	$0.00053	$0.19043
20	D-LI (CARE)	Wntr	Tier #3 All Other Use					$0.09931	$0.00884	$0.10815	$0.02640	$0.10786	$0.01383	$0.14809	$0.01408	$0.00053	$0.27085
21																	
22	Seasonal Residential																

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
23	DO (Seas)	Sumr	Tier #1	$0.21	$0.85			$0.17240	$0.01105	$0.18345	$0.03300	$0.10855	$0.01729	$0.15884	0.02479	0.00053	$0.36761
24	DO (Seas)	Sumr	Tier #2					$0.17240	$0.01105	$0.18345	$0.03300	$0.10855	$0.01729	$0.15884	0.02479	0.00053	$0.36761
25	DO (Seas)	Wntr	Tier #1	$0.21	$0.85			$0.17240	$0.01105	$0.18345	$0.03300	$0.10855	$0.01729	$0.15884	0.02479	0.00053	$0.36761
26	DO (Seas)	Wntr	Tier #2					$0.17240	$0.01105	$0.18345	$0.03300	$0.10855	$0.01729	$0.15884	0.02479	0.00053	$0.36761
27																	
28	Master Metered Apartments (No Submeters)																
29	DM (Perm)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.33			$0.08556	$0.01105	$0.09661	$0.03300	$0.02307	$0.01729	$0.07336	$0.02479	$0.00053	$0.19529
30	DM (Perm)	Sumr	Tier #2 130% BL					$0.11176	$0.01105	$0.12281	$0.03300	$0.04667	$0.01729	$0.09696	$0.02479	$0.00053	$0.24509
31	DM (Perm)	Sumr	Tier #3 All Other Use					$0.12414	$0.01105	$0.13519	$0.03300	$0.13482	$0.01729	$0.18511	$0.02479	$0.00053	$0.34562
32	DM (Perm)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.33			$0.08556	$0.01105	$0.09661	$0.03300	$0.02307	$0.01729	$0.07336	$0.02479	$0.00053	$0.19529
33	DM (Perm)	Wntr	Tier #2 130% BL					$0.11176	$0.01105	$0.12281	$0.03300	$0.04667	$0.01729	$0.09696	$0.02479	$0.00053	$0.24509
34	DM (Perm)	Wntr	Tier #3 All Other Use					$0.12414	$0.01105	$0.13519	$0.03300	$0.13482	$0.01729	$0.18511	$0.02479	$0.00053	$0.34562
35																	
36	Master Metered Mobilehome Parks																
37	DMS Meter	Sumr	Service Charge	$0.00				NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
38	DMS Meter	Wntr	Service Charge	$0.00				NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
39	DMS Meter	Sumr	Discount Per Occupied Unit	($0.10)				NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
40	DMS Meter	Wntr	Discount Per Occupied Unit	($0.10)				NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
41	Apply to Submetered Acct Under DMS																
42	D (Perm)	Sumr	Tier #1 Baseline (BL)	NA				$0.08556	$0.01105	$0.09661	$0.03300	$0.02307	$0.01729	$0.07336	$0.02479	$0.00053	$0.19529
43	D (Perm)	Sumr	Tier #2 130% BL					$0.11176	$0.01105	$0.12281	$0.03300	$0.04667	$0.01729	$0.09696	$0.02479	$0.00053	$0.24509
44	D (Perm)	Sumr	Tier #3 All Other Use					$0.12414	$0.01105	$0.13519	$0.03300	$0.13482	$0.01729	$0.18511	$0.02479	$0.00053	$0.34562
45	D (Perm)	Wntr	Tier #1 Baseline (BL)	NA				$0.08556	$0.01105	$0.09661	$0.03300	$0.02307	$0.01729	$0.07336	$0.02479	$0.00053	$0.19529
46	D (Perm)	Wntr	Tier #2 130% BL					$0.11176	$0.01105	$0.12281	$0.03300	$0.04667	$0.01729	$0.09696	$0.02479	$0.00053	$0.24509
47	D (Perm)	Wntr	Tier #3 All Other Use					$0.12414	$0.01105	$0.13519	$0.03300	$0.13482	$0.01729	$0.18511	$0.02479	$0.00053	$0.34562
48																	
49	D-LI (Perm)	Sumr	Tier #1 Baseline (BL)	NA				$0.06845	$0.00884	$0.07729	$0.02686	$0.01846	$0.01383	$0.05914	$0.01408	$0.00053	$0.15104
50	D-LI (Perm)	Sumr	Tier #2 130% BL					$0.08941	$0.00884	$0.09825	$0.02686	$0.03734	$0.01383	$0.07802	$0.01408	$0.00053	$0.19089
51	D-LI (Perm)	Sumr	Tier #3 All Other Use					$0.09931	$0.00884	$0.10815	$0.02686	$0.10786	$0.01383	$0.14854	$0.01408	$0.00053	$0.27131

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
52	D-LI (Perm)	Wntr	Tier #1 Baseline (BL)	NA				$0.06845	$0.00884	$0.07729	$0.02686	$0.01846	$0.01383	$0.05914	$0.01408	$0.00053	$0.15104
53	D-LI (Perm)	Wntr	Tier #2 130% BL					$0.08941	$0.00884	$0.09825	$0.02686	$0.03734	$0.01383	$0.07802	$0.01408	$0.00053	$0.19089
54	D-LI (Perm)	Wntr	Tier #3 All Other Use					$0.09931	$0.00884	$0.10815	$0.02686	$0.10786	$0.01383	$0.14854	$0.01408	$0.00053	$0.27131
55																	
56	DO (Seas)	Sumr	Tier #1					$0.17240	$0.01105	$0.18345	$0.03300	$0.10855	$0.01729	$0.15884	$0.02479	$0.00053	$0.36761
57	DO (Seas)	Sumr	Tier #2					$0.17240	$0.01105	$0.18345	$0.03300	$0.10855	$0.01729	$0.15884	$0.02479	$0.00053	$0.36761
58	DO (Seas)	Wntr	Tier #1					$0.17240	$0.01105	$0.18345	$0.03300	$0.10855	$0.01729	$0.15884	$0.02479	$0.00053	$0.36761
59	DO (Seas)	Wntr	Tier #2					$0.17240	$0.01105	$0.18345	$0.03300	$0.10855	$0.01729	$0.15884	$0.02479	$0.00053	$0.36761
60																	
61	Commercial (Small to Large)																
62	A-1	Sumr	Tier #1	$0.45		$0.00		$0.13359	$0.01105	$0.14464	$0.03300	$0.05372	$0.01729	$0.10401	0.02479	0.00053	$0.27397
63	A-1	Sumr	Tier #2					$0.13359	$0.01105	$0.14464	$0.03300	$0.10462	$0.01729	$0.15491	0.02479	0.00053	$0.32487
64	A-1	Wntr	Tier #1	$0.45		$0.00		$0.13359	$0.01105	$0.14464	$0.03300	$0.05372	$0.01729	$0.10401	0.02479	0.00053	$0.27397
65	A-1	Wntr	Tier #2					$0.13359	$0.01105	$0.14464	$0.03300	$0.10462	$0.01729	$0.15491	0.02479	0.00053	$0.32487
66																	
67	A-2	Sumr	Tier #1	$2.36		$0.00		$0.13338	$0.01105	$0.14443	$0.03300	$0.05067	$0.01729	$0.10096	0.02479	0.00053	$0.27071
68	A-2	Sumr	Tier #2					$0.13338	$0.01105	$0.14443	$0.03300	$0.10157	$0.01729	$0.15186	0.02479	0.00053	$0.32161
69	A-2	Wntr	Tier #1	$2.36				$0.13338	$0.01105	$0.14443	$0.03300	$0.05067	$0.01729	$0.10096	0.02479	0.00053	$0.27071

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
70	A-2	Wntr	Tier #2			$0.00		$0.13338	$0.01105	$0.14443	$0.03300	$0.10157	$0.01729	$0.15186	0.02479	0.00053	$0.32161
71																	
72	A-3	Sumr	Demand			$9.00											
73	A-3	Sumr	Tier #1	$6.60				$0.11855	$0.01105	$0.12960	$0.03300	$0.04417	$0.01729	$0.09446	0.02479	0.00053	$0.24938
74	A-3	Sumr	Tier #2					$0.11855	$0.01105	$0.12960	$0.03300	$0.09507	$0.01729	$0.14536	0.02479	0.00053	$0.30028
75	A-3	Wntr	Demand			$9.00											
76	A-3	Wntr	Tier #1	$6.60				$0.11855	$0.01105	$0.12960	$0.03300	$0.04417	$0.01729	$0.09446	0.02479	0.00053	$0.24938
77	A-3	Wntr	Tier #2					$0.11855	$0.01105	$0.12960	$0.03300	$0.09507	$0.01729	$0.14536	0.02479	0.00053	$0.30028
78																	
79	GSD	Sumr	Demand			$9.00											
80	GSD	Sumr	Tier #1	$0.23				$0.10000	$0.01105	$0.11105	$0.03300	$0.03987	$0.01729	$0.09016	0.02479	0.00053	$0.22653
81	GSD	Wntr	Demand			$9.00											
82	GSD	Wntr	Tier #1	$0.23				$0.11387	$0.01105	$0.12492	$0.03300	$0.03987	$0.01729	$0.09016	0.02479	0.00053	$0.24040
83																	
84	Very Large Customer Time-Of-Use																
85	A-4 TOU	Sumr	Fixed Charges	$16.40	$3.00												
86	A-4 TOU	Sumr	Max Demand			$0.00											
87	A-4 TOU	Sumr	On-Pk $/kW & /kWh			$10.00	$0.00	$0.11066	$0.01105	$0.12171	$0.03300	$0.12462	$0.01729	$0.17491	$0.02479	$0.00053	$0.32194
88	A-4 TOU	Sumr	Mid-Pk $/kW & /kWh					$0.11066	$0.01105	$0.12171	$0.03300	$0.09122	$0.01729	$0.14151	$0.02479	$0.00053	$0.28854

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
89	A-4 TOU	Sumr	Off-Pk $/kW & /kWh					$0.11066	$0.01105	$0.12171	$0.03300	$0.06895	$0.01729	$0.11924	$0.02479	$0.00053	$0.26627
90	A-4 TOU	Wntr	Fixed Charges	$16.40	$3.00												
91	A-4 TOU	Wntr	Max Demand			$0.00											
92	A-4 TOU	Wntr	On-Pk $/kW & /kWh			$10.00	$0.00	$0.11066	$0.01105	$0.12171	$0.03300	$0.12462	$0.01729	$0.17491	$0.02479	$0.00053	$0.32194
93	A-4 TOU	Wntr	Mid-Pk $/kW & /kWh					$0.11066	$0.01105	$0.12171	$0.03300	$0.09122	$0.01729	$0.14151	$0.02479	$0.00053	$0.28854
94	A-4 TOU	Wntr	Off-Pk $/kW & /kWh					$0.11066	$0.01105	$0.12171	$0.03300	$0.06895	$0.01729	$0.11924	$0.02479	$0.00053	$0.26627
95																	
96	A-5 TOU/Sec	Sumr	Fixed Charges	$65.80	$1.50												
97	A-5 TOU/Sec	Sumr	Max Demand			$4.30											
98	A-5 TOU/Sec	Sumr	FIRM On-Pk $/kW & /kWh			$12.38	$4.60	$0.04760	$0.01105	$0.05865	$0.03300	$0.06856	$0.01729	$0.11885	$0.02479	$0.00053	$0.20282
99	A-5 TOU/Sec	Sumr	NON-FIRM On-Pk $/kW & /kWh			$7.00	$4.60	$0.04760	$0.01105	$0.05865	$0.03300	$0.06856	$0.01729	$0.11885	$0.02479	$0.00053	$0.20282
100	A-5 TOU/Sec	Sumr	Mid-Pk $/kW & /kWh			$3.50		$0.04760	$0.01105	$0.05865	$0.03300	$0.03761	$0.01729	$0.08790	$0.02479	$0.00053	$0.17187

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
101	A-5 TOU/Sec	Sumr	Off-Pk $/kW & /kWh					$0.04760	$0.01105	$0.05865	$0.03300	$0.02421	$0.01729	$0.07450	$0.02479	$0.00053	$0.15847
102	A-5 TOU/Sec	Wntr	Fixed Charges	$65.80	$1.50												
103	A-5 TOU/Sec	Wntr	Max Demand			$4.30											
104	A-5 TOU/Sec	Wntr	FIRM On-Pk $/kW & /kWh			$12.38	$4.60	$0.04760	$0.01105	$0.05865	$0.03300	$0.06856	$0.01729	$0.11885	$0.02479	$0.00053	$0.20282
105	A-5 TOU/Sec	Wntr	NON-FIRM On-Pk $/kW & /kWh			$7.00	$4.60	$0.04760	$0.01105	$0.05865	$0.03300	$0.06856	$0.01729	$0.11885	$0.02479	$0.00053	$0.20282
106	A-5 TOU/Sec	Wntr	Mid-Pk $/kW & /kWh			$3.50		$0.04760	$0.01105	$0.05865	$0.03300	$0.03761	$0.01729	$0.08790	$0.02479	$0.00053	$0.17187
107	A-5 TOU/Sec	Wntr	Off-Pk $/kW & /kWh					$0.04760	$0.01105	$0.05865	$0.03300	$0.02421	$0.01729	$0.07450	$0.02479	$0.00053	$0.15847
108																	
109	A-5 TOU/Pri	Sumr	Fixed Charges	$65.80	$1.50												
110	A-5 TOU/Pri	Sumr	Max Demand			$4.30											
111	A-5 TOU/Pri	Sumr	FIRM On-Pk $/kW & /kWh			$12.38		$0.01638	$0.01105	$0.02743	$0.03300	$0.06657	$0.01729	$0.11686	$0.02479	$0.00053	$0.16961
112	A-5 TOU/Pri	Sumr	NON-FIRM On-Pk $/kW & /kWh			$6.00		$0.01638	$0.01105	$0.02743	$0.03300	$0.06657	$0.01729	$0.11686	$0.02479	$0.00053	$0.16961

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
113	A-5 TOU/Pri	Sumr	Mid-Pk $/kW & /kWh			$3.50		$0.01638	$0.01105	$0.02743	$0.03300	$0.03632	$0.01729	$0.08661	$0.02479	$0.00053	$0.13936
114	A-5 TOU/Pri	Sumr	Off-Pk $/kW & /kWh					$0.01638	$0.01105	$0.02743	$0.03300	$0.02322	$0.01729	$0.07351	$0.02479	$0.00053	$0.12626
115	A-5 TOU/Pri	Wntr	Fixed Charges	$65.80	$1.50												
116	A-5 TOU/Pri	Wntr	Max Demand			$4.30											
117	A-5 TOU/Pri	Wntr	FIRM On-Pk $/kW & /kWh			$12.38		$0.01638	$0.01105	$0.02743	$0.03300	$0.06657	$0.01729	$0.11686	$0.02479	$0.00053	$0.16961
118	A-5 TOU/Pri	Wntr	NON-FIRM On-Pk $/kW & /kWh			$6.00		$0.01638	$0.01105	$0.02743	$0.03300	$0.06657	$0.01729	$0.11686	$0.02479	$0.00053	$0.16961
119	A-5 TOU/Pri	Wntr	Mid-Pk $/kW & /kWh			$3.50		$0.01638	$0.01105	$0.02743	$0.03300	$0.03632	$0.01729	$0.08661	$0.02479	$0.00053	$0.13936
120	A-5 TOU/Pri	Wntr	Off-Pk $/kW & /kWh					$0.01638	$0.01105	$0.02743	$0.03300	$0.02322	$0.01729	$0.07351	$0.02479	$0.00053	$0.12626
121																	
122	Street Lighting																
123	SL	Sumr	Customer	$0.21													
124	SL	Sumr	Facilities Charge/Lamp/day	$0.4340													
125	SL	Sumr	Energy Charge					$0.13666	$0.01105	$0.16306	$0.03300	$0.03631	$0.01729	$0.08660	$0.02479	$0.00053	$0.27498
126	SL	Wntr	Customer	$0.21													

Exhibit C

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj* $/kWh	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
127	SL	Wntr	Facilities Charge	$0.434													
128	SL	Wntr	Energy Charge					$0.13666	$0.01105	$0.16306	$0.03300	$0.03631	$0.01729	$0.08660	$0.02479	$0.00053	$0.27498

a. *The “Base Energy Adjustment” is an estimate of the expected BRRAM surcharge. The actual, authorized BRRAM surcharges in effect at the time rates are authorized will be substituted for this placeholder value.

b. ** The “All Other Charges” consist of Public Purpose Charges, the Renewable Portfolio Standard energy surcharge, and the Catastrophic Event Memo Account surcharge. Supply charges are not included in these charges. Charges shown are an estimate of the expected charges. The actual “other” charges in effect at the time rates are authorized will be substituted for these placeholder values.

c. Residential Minimum Charge: A minimum charge ($ per day) is applied to the calculation of the total bill will be assessed when the sum of the Service Charge, Base Energy, Transmission Charge, Supply Charge is less than the specified Minimum Charge.

d. Non-Residential Minimum Charge: A minimum charge ($ per KW) is applied to the calculation of the total bill and will be assessed when the sum of the Base Energy, Base Adjustment, Transmission Charge, Energy Charge, Supply Adjustment Charge and all Demand charges is less than the specified Minimum Charge.

e. A-4 Minimum Charge: Will be equal to the Service Charge per meter, per day, plus $1.50 per kW times Contract Demand (New Special Condition 7). New Special Condition 7 indicates “Contract Demand: Is the demand determined, at BVES’ option, by an engineering evaluation of the connected load.”

(END OF APPENDIX B)

Appendix C
Adopted Base Rates

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg*	Base Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	All Other Charges	Regltry Fees $/kWh	TOTAL Base Energy Chrg
Permanent Residential												
1	D (Perm)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.21		$0.08353	$0.01105	**$0.09458**	$0.02479	$ 0.00053	**$0.11990**
2	D (Perm)	Sumr	Tier #2 130% BL				$0.10900	$0.01105	**$0.12005**	$0.02479	$ 0.00053	**$0.14537**
3	D (Perm)	Sumr	Tier #3 All Other Use				$0.13091	$0.01105	**$0.14196**	$0.02479	$ 0.00053	**$0.16728**
4	D (Perm)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.21		$0.08353	$0.01105	**$0.09458**	$0.02479	$ 0.00053	**$0.11990**
5	D (Perm)	Wntr	Tier #2 130% BL				$0.10900	$0.01105	**$0.12005**	$0.02479	$ 0.00053	**$0.14537**
6	D (Perm)	Wntr	Tier #3 All Other Use				$0.13091	$0.01105	**$0.14196**	$0.02479	$ 0.00053	**$0.16728**
7												
8	D (Employee)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.21		$0.04176	$0.01105	**$0.05281**	$0.02479	$ 0.00053	**$0.07813**
9	D (Employee)	Sumr	Tier #2 130% BL				$0.05450	$0.01105	**$0.06555**	$0.02479	$ 0.00053	**$0.09087**
10	D (Employee)	Sumr	Tier #3 All Other Use				$0.06545	$0.01105	**$0.07650**	$0.02479	$ 0.00053	**$0.10182**
11	D (Employee)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.21		$0.04176	$0.01105	**$0.05281**	$0.02479	$ 0.00053	**$0.07813**
12	D (Employee)	Wntr	Tier #2 130% BL				$0.05450	$0.01105	**$0.06555**	$0.02479	$ 0.00053	**$0.09087**
13	D (Employee)	Wntr	Tier #3 All Other Use				$0.06545	$0.01105	**$0.07650**	$0.02479	$ 0.00053	**$0.10182**
14												
15	D-LI (CARE)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.168		$0.06682	$0.00884	**$0.07566**	$0.01408	$ 0.00053	**$0.09027**
16	D-LI (CARE)	Sumr	Tier #2 130% BL				$0.08720	$0.00884	**$0.09604**	$0.01408	$ 0.00053	**$0.11065**
17	D-LI (CARE)	Sumr	Tier #3 All Other Use				$0.10473	$0.00884	**$0.11357**	$0.01408	$ 0.00053	**$0.12818**
18	D-LI (CARE)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.168		$0.06682	$0.00884	**$0.07566**	$0.01408	$ 0.00053	**$0.09027**
19	D-LI (CARE)	Wntr	Tier #2 130% BL				$0.08720	$0.00884	**$0.09604**	$0.01408	$ 0.00053	**$0.11065**
20	D-LI (CARE)	Wntr	Tier #3 All Other Use				$0.10473	$0.00884	**$0.11357**	$0.01408	$ 0.00053	**$0.12818**
21												
22	**Seasonal Residential**											
23	DO (Seas)	Sumr	Tier #1	$0.21	$0.85		$0.17240	$0.01105	**$0.18345**	$0.02479	$ 0.00053	**$0.20877**
24	DO (Seas)	Sumr	Tier #2				$0.17240	$0.01105	**$0.18345**	$0.02479	$ 0.00053	**$0.20877**
25	DO (Seas)	Wntr	Tier #1	$0.21	$0.85		$0.17240	$0.01105	**$0.18345**	$0.02479	$ 0.00053	**$0.20877**
26	DO (Seas)	Wntr	Tier #2				$0.17240	$0.01105	**$0.18345**	$0.02479	$ 0.00053	**$0.20877**
27												
28	**Master Metered Apartments (No Submeters)**											
29	DM (Perm)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.21		$0.08353	$0.01105	**$0.09458**	$0.02479	$ 0.00053	**$0.11990**
30	DM (Perm)	Sumr	Tier #2 130% BL				$0.10900	$0.01105	**$0.12005**	$0.02479	$ 0.00053	**$0.14537**
31	DM (Perm)	Sumr	Tier #3 All Other Use				$0.13091	$0.01105	**$0.14196**	$0.02479	$ 0.00053	**$0.16728**
32	DM (Perm)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.21		$0.08353	$0.01105	**$0.09458**	$0.02479	$ 0.00053	**$0.11990**
33	DM (Perm)	Wntr	Tier #2 130% BL				$0.10900	$0.01105	**$0.12005**	$0.02479	$ 0.00053	**$0.14537**
34	DM (Perm)	Wntr	Tier #3 All Other Use				$0.13091	$0.01105	**$0.14196**	$0.02479	$ 0.00053	**$0.16728**

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg*	Base Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	All Other Charges	Regltry Fees $/kWh	TOTAL Base Energy Chrg
36	Master Metered Mobilehome Parks											
37	DMS Meter	Sumr	Service Charge	**$0.00**			NA	NA	**NA**			**NA**
38	DMS Meter	Wntr	Service Charge	**$0.00**			NA	NA	**NA**			**NA**
39	DMS Meter	Sumr	Discount Per Occupied Ur	($0.100)			NA	NA	**NA**			**NA**
40	DMS Meter	Wntr	Discount Per Occupied Ur	($0.100)			NA	NA	**NA**			**NA**
41	*Apply to Submetered Acct Under DMS*											
42	D (Perm)	Sumr	Tier #1 Baseline (BL)	NA			$0.08353	$0.01105	**$0.09458**	$0.02479	$ 0.00053	**$0.11990**
43	D (Perm)	Sumr	Tier #2 130% BL				$0.10900	$0.01105	**$0.12005**	$0.02479	$ 0.00053	**$0.14537**
44	D (Perm)	Sumr	Tier #3 All Other Use				$0.13091	$0.01105	**$0.14196**	$0.02479	$ 0.00053	**$0.16728**
45	D (Perm)	Wntr	Tier #1 Baseline (BL)	NA			$0.08353	$0.01105	**$0.09458**	$0.02479	$ 0.00053	**$0.11990**
46	D (Perm)	Wntr	Tier #2 130% BL				$0.10900	$0.01105	**$0.12005**	$0.02479	$ 0.00053	**$0.14537**
47	D (Perm)	Wntr	Tier #3 All Other Use				$0.13091	$0.01105	**$0.14196**	$0.02479	$ 0.00053	**$0.16728**
48												
49	D-LI (Perm)	Sumr	Tier #1 Baseline (BL)	NA			$0.06682	$0.00884	**$0.07566**	$0.01408	$ 0.00053	**$0.09027**
50	D-LI (Perm)	Sumr	Tier #2 130% BL				$0.08720	$0.00884	**$0.09604**	$0.01408	$ 0.00053	**$0.11065**
51	D-LI (Perm)	Sumr	Tier #3 All Other Use				$0.10473	$0.00884	**$0.11357**	$0.01408	$ 0.00053	**$0.12818**
52	D-LI (Perm)	Wntr	Tier #1 Baseline (BL)	NA			$0.06682	$0.00884	**$0.07566**	$0.01408	$ 0.00053	**$0.09027**
53	D-LI (Perm)	Wntr	Tier #2 130% BL				$0.08720	$0.00884	**$0.09604**	$0.01408	$ 0.00053	**$0.11065**
54	D-LI (Perm)	Wntr	Tier #3 All Other Use				$0.10473	$0.00884	**$0.11357**	$0.01408	$ 0.00053	**$0.12818**
55												
56	DO (Seas)	Sumr	Tier #1				$0.17240	$0.01105	**$0.18345**	$0.02479	$ 0.00053	**$0.20877**
57	DO (Seas)	Sumr	Tier #2				$0.17240	$0.01105	**$0.18345**	$0.02479	$ 0.00053	**$0.20877**
58	DO (Seas)	Wntr	Tier #1				$0.17240	$0.01105	**$0.18345**	$0.02479	$ 0.00053	**$0.20877**
59	DO (Seas)	Wntr	Tier #2				$0.17240	$0.01105	**$0.18345**	$0.02479	$ 0.00053	**$0.20877**
60												
61	Commercial (Small to Large)											
62	A-1	Sumr	Tier #1	$0.45		$0.00	$0.13359	$0.01105	**$0.14464**	$0.02479	$ 0.00053	**$0.16996**
63	A-1	Sumr	Tier #2				$0.13359	$0.01105	**$0.14464**	$0.02479	$ 0.00053	**$0.16996**
64	A-1	Wntr	Tier #1	$0.45		$0.00	$0.13359	$0.01105	**$0.14464**	$0.02479	$ 0.00053	**$0.16996**
65	A-1	Wntr	Tier #2				$0.13359	$0.01105	**$0.14464**	$0.02479	$ 0.00053	**$0.16996**
66												
67	A-2	Sumr	Tier #1	$2.36		$0.00	$0.13338	$0.01105	**$0.14443**	$0.02479	$ 0.00053	**$0.16975**
68	A-2	Sumr	Tier #2				$0.13338	$0.01105	**$0.14443**	$0.02479	$ 0.00053	**$0.16975**
69	A-2	Wntr	Tier #1	$2.36		$0.00	$0.13338	$0.01105	**$0.14443**	$0.02479	$ 0.00053	**$0.16975**
70	A-2	Wntr	Tier #2				$0.13338	$0.01105	**$0.14443**	$0.02479	$ 0.00053	**$0.16975**
71												
72	A-3	Sumr	Demand			$9.00						
73	A-3	Sumr	Tier #1	$ 6.60			$0.11855	$0.01105	**$0.12960**	$0.02479	$ 0.00053	**$0.15492**
74	A-3	Sumr	Tier #2				$0.11855	$0.01105	**$0.12960**	$0.02479	$ 0.00053	**$0.15492**
75	A-3	Wntr	Demand			$9.00						
76	A-3	Wntr	Tier #1	$ 6.60			$0.11855	$0.01105	**$0.12960**	$0.02479	$ 0.00053	**$0.15492**
77	A-3	Wntr	Tier #2				$0.11855	$0.01105	**$0.12960**	$0.02479	$ 0.00053	**$0.15492**
78												
79	GSD	Sumr	Demand			$9.00						
80	GSD	Sumr	Tier #1	$0.23			$0.10000	$0.01105	**$0.11105**	$0.02479	$ 0.00053	**$0.13637**
81	GSD	Wntr	Demand			$9.00						
82	GSD	Wntr	Tier #1	$0.23			$0.11387	$0.01105	**$0.12492**	$0.02479	$ 0.00053	**$0.15024**

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg*	Base Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	All Other Charges	Regltry Fees $/kWh	TOTAL Base Energy Chrg
84	**Very Large Customer Time-Of-Use**											
85	A-4 TOU	Sumr	Fixed Charges	$16.40	$3.00							
86	A-4 TOU	Sumr	Max Demand			$0.00						
87	A-4 TOU	Sumr	On-Pk $//kW & /kWh			$10.00	$0.11066	$0.01105	**$0.12171**	$0.02479	$ 0.00053	**$0.14703**
88	A-4 TOU	Sumr	Mid-Pk $//kW & /kWh				$0.11066	$0.01105	**$0.12171**	$0.02479	$ 0.00053	**$0.14703**
89	A-4 TOU	Sumr	Off-Pk $//kW & /kWh				$0.11066	$0.01105	**$0.12171**	$0.02479	$ 0.00053	**$0.14703**
90	A-4 TOU	Wntr	Fixed Charges	$16.40	$3.00							
91	A-4 TOU	Wntr	Max Demand			$0.00						
92	A-4 TOU	Wntr	On-Pk $//kW & /kWh			$10.00	$0.11066	$0.01105	**$0.12171**	$0.02479	$ 0.00053	**$0.14703**
93	A-4 TOU	Wntr	Mid-Pk $//kW & /kWh				$0.11066	$0.01105	**$0.12171**	$0.02479	$ 0.00053	**$0.14703**
94	A-4 TOU	Wntr	Off-Pk $//kW & /kWh				$0.11066	$0.01105	**$0.12171**	$0.02479	$ 0.00053	**$0.14703**
95												
96	A-5 TOU/Sec	Sumr	Fixed Charges	$65.80	$1.50							
97	A-5 TOU/Sec	Sumr	Max Demand			$4.30						
98	A-5 TOU/Sec	Sumr	FIRM BASE On-Pk $//kW & /kWh			$12.38						
99	A-5 TOU/Sec	Sumr	NON-FIRM BASE On-Pk $//kW & /kWh			$7.00	$0.04760	$0.01105	**$0.05865**	$0.02479	$ 0.00053	**$0.08397**
100	A-5 TOU/Sec	Sumr	Mid-Pk $//kW & /kWh			$3.50	$0.04760	$0.01105	**$0.05865**	$0.02479	$ 0.00053	**$0.08397**
101	A-5 TOU/Sec	Sumr	Off-Pk $//kW & /kWh				$0.04760	$0.01105	**$0.05865**	$0.02479	$ 0.00053	**$0.08397**
102	A-5 TOU/Sec	Wntr	Fixed Charges	$65.80	$1.50							
103	A-5 TOU/Sec	Wntr	Max Demand			$4.30						
104	A-5 TOU/Sec	Wntr	FIRM BASE On-Pk $//kW & /kWh			$12.38						
105	A-5 TOU/Sec	Wntr	NON-FIRM BASE On-Pk $//kW & /kWh			$7.00	$0.04760	$0.01105	**$0.05865**	$0.02479	$ 0.00053	**$0.08397**
106	A-5 TOU/Sec	Wntr	Mid-Pk $//kW & /kWh			$3.50	$0.04760	$0.01105	**$0.05865**	$0.02479	$ 0.00053	**$0.08397**
107	A-5 TOU/Sec	Wntr	Off-Pk $//kW & /kWh				$0.04760	$0.01105	**$0.05865**	$0.02479	$ 0.00053	**$0.08397**
108												
109	A-5 TOU/Pri	Sumr	Fixed Charges	$65.80	$1.50							
110	A-5 TOU/Pri	Sumr	Max Demand			$4.30						
111	A-5 TOU/Pri	Sumr	FIRM BASE On-Pk $//kW & /kWh			$12.38						
112	A-5 TOU/Pri	Sumr	NON-FIRM BASE On-Pk $//kW & /kWh			$6.00	$0.01638	$0.01105	**$0.02743**	$0.02479	$ 0.00053	**$0.05275**
113	A-5 TOU/Pri	Sumr	Mid-Pk $//kW & /kWh			$3.50	$0.01638	$0.01105	**$0.02743**	$0.02479	$ 0.00053	**$0.05275**
114	A-5 TOU/Pri	Sumr	Off-Pk $//kW & /kWh				$0.01638	$0.01105	**$0.02743**	$0.02479	$ 0.00053	**$0.05275**
115	A-5 TOU/Pri	Wntr	Fixed Charges	$65.80	$1.50							
116	A-5 TOU/Pri	Wntr	Max Demand			$4.30						
117	A-5 TOU/Pri	Wntr	FIRM BASE On-Pk $//kW & /kWh			$12.38						
118	A-5 TOU/Pri	Wntr	NON-FIRM BASE On-Pk $//kW & /kWh			$6.00	$0.01638	$0.01105	**$0.02743**	$0.02479	$ 0.00053	**$0.05275**
119	A-5 TOU/Pri	Wntr	Mid-Pk $//kW & /kWh			$3.50	$0.01638	$0.01105	**$0.02743**	$0.02479	$ 0.00053	**$0.05275**
120	A-5 TOU/Pri	Wntr	Off-Pk $//kW & /kWh				$0.01638	$0.01105	**$0.02743**	$0.02479	$ 0.00053	**$0.05275**

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg*	Base Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	All Other Charges	Regltry Fees $/kWh	TOTAL Base Energy Chrg
122	**Street Lighting**											
123	SL	Sumr	Customer	$0.21								
124	SL	Sumr	Facilities Charge/Lamp/da	$0.4340								
125	SL	Sumr	Energy Charge				$0.13666	$0.01105	**$0.16306**	$0.02479	$ 0.00053	**$0.27498**
126	SL	Wntr	Customer	$0.21								
127	SL	Wntr	Facilities Charge	$0.4340								
128	SL	Wntr	Energy Charge				$0.13666	$0.01105	**$0.16306**	$0.02479	$ 0.00053	**$0.27498**
	*This Adjustment is an estimated of the expected BBRAM surcharge for an undercolleciton in 2011.											
	The actual authorized BRRAM surcharges in effect at the time rates are set will be substituted for this place holder value.											

(END OF APPENDIX C)

Appendix D
Adopted Total Rates

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regitry Fees $/kWh	TOTAL Energy Chrg
Permanent Residential																	
1	D (Perm)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.21			$0.08353	$0.01105	**$0.09458**	$0.03300	$0.02307	$0.01729	**$0.07336**	$0.02479	$ 0.00053	**$0.19326**
2	D (Perm)	Sumr	Tier #2 130% BL					$0.10900	$0.01105	**$0.12005**	$0.03300	$0.04667	$0.01729	**$0.09696**	$0.02479	$ 0.00053	**$0.24233**
3	D (Perm)	Sumr	Tier #3 All Other Use					$0.13091	$0.01105	**$0.14196**	$0.03300	$0.13482	$0.01729	**$0.18511**	$0.02479	$ 0.00053	**$0.35239**
4	D (Perm)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.21			$0.08353	$0.01105	**$0.09458**	$0.03300	$0.02307	$0.01729	**$0.07336**	$0.02479	$ 0.00053	**$0.19326**
5	D (Perm)	Wntr	Tier #2 130% BL					$0.10900	$0.01105	**$0.12005**	$0.03300	$0.04667	$0.01729	**$0.09696**	$0.02479	$ 0.00053	**$0.24233**
6	D (Perm)	Wntr	Tier #3 All Other Use					$0.13091	$0.01105	**$0.14196**	$0.03300	$0.13482	$0.01729	**$0.18511**	$0.02479	$ 0.00053	**$0.35239**
7																	
8	D (Employee)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.21			$0.04176	$0.01105	**$0.05281**	$0.01650	$0.01154	$0.00865	**$0.03668**	$0.02479	$ 0.00053	**$0.11481**
9	D (Employee)	Sumr	Tier #2 130% BL					$0.05450	$0.01105	**$0.06555**	$0.01650	$0.02334	$0.00865	**$0.04848**	$0.02479	$ 0.00053	**$0.13935**
10	D (Employee)	Sumr	Tier #3 All Other Use					$0.06545	$0.01105	**$0.07650**	$0.01650	$0.06741	$0.00865	**$0.09256**	$0.02479	$ 0.00053	**$0.19438**
11	D (Employee)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.21			$0.04176	$0.01105	**$0.05281**	$0.01650	$0.01154	$0.00865	**$0.03668**	$0.02479	$ 0.00053	**$0.11481**
12	D (Employee)	Wntr	Tier #2 130% BL					$0.05450	$0.01105	**$0.06555**	$0.01650	$0.02334	$0.00865	**$0.04848**	$0.02479	$ 0.00053	**$0.13935**
13	D (Employee)	Wntr	Tier #3 All Other Use					$0.06545	$0.01105	**$0.07650**	$0.01650	$0.06741	$0.00865	**$0.09256**	$0.02479	$ 0.00053	**$0.19438**
14																	
15	D-LI (CARE)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.168			$0.06682	$0.00884	**$0.07566**	$0.02640	$0.01846	$0.01383	**$0.05869**	$0.01408	$ 0.00053	**$0.14896**
16	D-LI (CARE)	Sumr	Tier #2 130% BL					$0.08720	$0.00884	**$0.09604**	$0.02640	$0.03734	$0.01383	**$0.07757**	$0.01408	$ 0.00053	**$0.18822**
17	D-LI (CARE)	Sumr	Tier #3 All Other Use					$0.10473	$0.00884	**$0.11357**	$0.02640	$0.10786	$0.01383	**$0.14809**	$0.01408	$ 0.00053	**$0.27627**
18	D-LI (CARE)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.168			$0.06682	$0.00884	**$0.07566**	$0.02640	$0.01846	$0.01383	**$0.05869**	$0.01408	$ 0.00053	**$0.14896**
19	D-LI (CARE)	Wntr	Tier #2 130% BL					$0.08720	$0.00884	**$0.09604**	$0.02640	$0.03734	$0.01383	**$0.07757**	$0.01408	$ 0.00053	**$0.18822**
20	D-LI (CARE)	Wntr	Tier #3 All Other Use					$0.10473	$0.00884	**$0.11357**	$0.02640	$0.10786	$0.01383	**$0.14809**	$0.01408	$ 0.00053	**$0.27627**

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
22	**Seasonal Residential**																
23	DO (Seas)	Sumr	Tier #1	$0.21	$0.85			$0.17240	$0.01105	**$0.18345**	$0.03300	$0.10855	$0.01729	**$0.15884**	$0.02479	$ 0.00053	**$0.36761**
24	DO (Seas)	Sumr	Tier #2					$0.17240	$0.01105	**$0.18345**	$0.03300	$0.10855	$0.01729	**$0.15884**	$0.02479	$ 0.00053	**$0.36761**
25	DO (Seas)	Wntr	Tier #1	$0.21	$0.85			$0.17240	$0.01105	**$0.18345**	$0.03300	$0.10855	$0.01729	**$0.15884**	$0.02479	$ 0.00053	**$0.36761**
26	DO (Seas)	Wntr	Tier #2					$0.17240	$0.01105	**$0.18345**	$0.03300	$0.10855	$0.01729	**$0.15884**	$0.02479	$ 0.00053	**$0.36761**
27																	
28	**Master Metered Apartments (No Submeters)**																
29	DM (Perm)	Sumr	Tier #1 Baseline (BL)	$0.00	$0.21			$0.08353	$0.01105	**$0.09458**	$0.03300	$0.02307	$0.01729	**$0.07336**	$0.02479	$ 0.00053	**$0.19326**
30	DM (Perm)	Sumr	Tier #2 130% BL					$0.10900	$0.01105	**$0.12005**	$0.03300	$0.04667	$0.01729	**$0.09696**	$0.02479	$ 0.00053	**$0.24233**
31	DM (Perm)	Sumr	Tier #3 All Other Use					$0.13091	$0.01105	**$0.14196**	$0.03300	$0.13482	$0.01729	**$0.18511**	$0.02479	$ 0.00053	**$0.35239**
32	DM (Perm)	Wntr	Tier #1 Baseline (BL)	$0.00	$0.21			$0.08353	$0.01105	**$0.09458**	$0.03300	$0.02307	$0.01729	**$0.07336**	$0.02479	$ 0.00053	**$0.19326**
33	DM (Perm)	Wntr	Tier #2 130% BL					$0.10900	$0.01105	**$0.12005**	$0.03300	$0.04667	$0.01729	**$0.09696**	$0.02479	$ 0.00053	**$0.24233**
34	DM (Perm)	Wntr	Tier #3 All Other Use					$0.13091	$0.01105	**$0.14196**	$0.03300	$0.13482	$0.01729	**$0.18511**	$0.02479	$ 0.00053	**$0.35239**

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
36	**Master Metered Mobilehome Parks**																
37	DMS Meter	Sumr	Service Charge	**$0.00**				NA	NA	**NA**	NA	NA	NA	NA	NA	NA	**NA**
38	DMS Meter	Wntr	Service Charge	**$0.00**				NA	NA	**NA**	NA	NA	NA	NA	NA	NA	**NA**
39	DMS Meter	Sumr	Discount Per Occupied Unit	($0.100)				NA	NA	**NA**	NA	NA	NA	NA	NA	NA	**NA**
40	DMS Meter	Wntr	Discount Per Occupied Unit	($0.100)				NA	NA	**NA**	NA	NA	NA	NA	NA	NA	**NA**
41	*Apply to Submetered Acct Under DMS*																
42	D (Perm)	Sumr	Tier #1 Baseline (BL)	NA				$0.08353	$0.01105	**$0.09458**	$0.03300	$0.02307	$0.01729	**$0.07336**	$0.02479	$ 0.00053	**$0.19326**
43	D (Perm)	Sumr	Tier #2 130% BL					$0.10900	$0.01105	**$0.12005**	$0.03300	$0.04667	$0.01729	**$0.09696**	$0.02479	$ 0.00053	**$0.24233**
44	D (Perm)	Sumr	Tier #3 All Other Use					$0.13091	$0.01105	**$0.14196**	$0.03300	$0.13482	$0.01729	**$0.18511**	$0.02479	$ 0.00053	**$0.35239**
45	D (Perm)	Wntr	Tier #1 Baseline (BL)	NA				$0.08353	$0.01105	**$0.09458**	$0.03300	$0.02307	$0.01729	**$0.07336**	$0.02479	$ 0.00053	**$0.19326**
46	D (Perm)	Wntr	Tier #2 130% BL					$0.10900	$0.01105	**$0.12005**	$0.03300	$0.04667	$0.01729	**$0.09696**	$0.02479	$ 0.00053	**$0.24233**
47	D (Perm)	Wntr	Tier #3 All Other Use					$0.13091	$0.01105	**$0.14196**	$0.03300	$0.13482	$0.01729	**$0.18511**	$0.02479	$ 0.00053	**$0.35239**
48																	
49	D-LI (Perm)	Sumr	Tier #1 Baseline (BL)	NA				$0.06682	$0.00884	**$0.07566**	$0.02686	$0.01846	$0.01383	**$0.05914**	$0.01408	$ 0.00053	**$0.14941**
50	D-LI (Perm)	Sumr	Tier #2 130% BL					$0.08720	$0.00884	**$0.09604**	$0.02686	$0.03734	$0.01383	**$0.07802**	$0.01408	$ 0.00053	**$0.18867**
51	D-LI (Perm)	Sumr	Tier #3 All Other Use					$0.10473	$0.00884	**$0.11357**	$0.02686	$0.10786	$0.01383	**$0.14854**	$0.01408	$ 0.00053	**$0.27672**
52	D-LI (Perm)	Wntr	Tier #1 Baseline (BL)	NA				$0.06682	$0.00884	**$0.07566**	$0.02686	$0.01846	$0.01383	**$0.05914**	$0.01408	$ 0.00053	**$0.14941**
53	D-LI (Perm)	Wntr	Tier #2 130% BL					$0.08720	$0.00884	**$0.09604**	$0.02686	$0.03734	$0.01383	**$0.07802**	$0.01408	$ 0.00053	**$0.18867**
54	D-LI (Perm)	Wntr	Tier #3 All Other Use					$0.10473	$0.00884	**$0.11357**	$0.02686	$0.10786	$0.01383	**$0.14854**	$0.01408	$ 0.00053	**$0.27672**
55																	
56	DO (Seas)	Sumr	Tier #1					$0.17240	$0.01105	**$0.18345**	$0.03300	$0.10855	$0.01729	**$0.15884**	$0.02479	$ 0.00053	**$0.36761**
57	DO (Seas)	Sumr	Tier #2					$0.17240	$0.01105	**$0.18345**	$0.03300	$0.10855	$0.01729	**$0.15884**	$0.02479	$ 0.00053	**$0.36761**
58	DO (Seas)	Wntr	Tier #1					$0.17240	$0.01105	**$0.18345**	$0.03300	$0.10855	$0.01729	**$0.15884**	$0.02479	$ 0.00053	**$0.36761**
59	DO (Seas)	Wntr	Tier #2					$0.17240	$0.01105	**$0.18345**	$0.03300	$0.10855	$0.01729	**$0.15884**	$0.02479	$ 0.00053	**$0.36761**

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
61	Commercial (Small to Large)																
62	A-1	Sumr	Tier #1	$0.45		$0.00		$0.13359	$0.01105	**$0.14464**	$0.03300	$0.05372	$0.01729	**$0.10401**	$0.02479	$ 0.00053	**$0.27397**
63	A-1	Sumr	Tier #2					$0.13359	$0.01105	**$0.14464**	$0.03300	$0.10462	$0.01729	**$0.15491**	$0.02479	$ 0.00053	**$0.32487**
64	A-1	Wntr	Tier #1	$0.45		$0.00		$0.13359	$0.01105	**$0.14464**	$0.03300	$0.05372	$0.01729	**$0.10401**	$0.02479	$ 0.00053	**$0.27397**
65	A-1	Wntr	Tier #2					$0.13359	$0.01105	**$0.14464**	$0.03300	$0.10462	$0.01729	**$0.15491**	$0.02479	$ 0.00053	**$0.32487**
66																	
67	A-2	Sumr	Tier #1	$2.36				$0.13338	$0.01105	**$0.14443**	$0.03300	$0.05067	$0.01729	**$0.10096**	$0.02479	$ 0.00053	**$0.27071**
68	A-2	Sumr	Tier #2					$0.13338	$0.01105	**$0.14443**	$0.03300	$0.10157	$0.01729	**$0.15186**	$0.02479	$ 0.00053	**$0.32161**
69	A-2	Wntr	Tier #1	$2.36				$0.13338	$0.01105	**$0.14443**	$0.03300	$0.05067	$0.01729	**$0.10096**	$0.02479	$ 0.00053	**$0.27071**
70	A-2	Wntr	Tier #2					$0.13338	$0.01105	**$0.14443**	$0.03300	$0.10157	$0.01729	**$0.15186**	$0.02479	$ 0.00053	**$0.32161**
71																	
72	A-3	Sumr	Demand			$9.00											
73	A-3	Sumr	Tier #1	$ 6.60				$0.11855	$0.01105	**$0.12960**	$0.03300	$0.04417	$0.01729	**$0.09446**	$0.02479	$ 0.00053	**$0.24938**
74	A-3	Sumr	Tier #2					$0.11855	$0.01105	**$0.12960**	$0.03300	$0.09507	$0.01729	**$0.14536**	$0.02479	$ 0.00053	**$0.30028**
75	A-3	Wntr	Demand			$9.00											
76	A-3	Wntr	Tier #1	$ 6.60				$0.11855	$0.01105	**$0.12960**	$0.03300	$0.04417	$0.01729	**$0.09446**	$0.02479	$ 0.00053	**$0.24938**
77	A-3	Wntr	Tier #2					$0.11855	$0.01105	**$0.12960**	$0.03300	$0.09507	$0.01729	**$0.14536**	$0.02479	$ 0.00053	**$0.30028**
78																	
79	GSD	Sumr	Demand			$9.00											
80	GSD	Sumr	Tier #1	$0.23				$0.10000	$0.01105	**$0.11105**	$0.03300	$0.03987	$0.01729	**$0.09016**	$0.02479	$ 0.00053	**$0.22653**
81	GSD	Wntr	Demand			$9.00											
82	GSD	Wntr	Tier #1	$0.23				$0.11387	$0.01105	**$0.12492**	$0.03300	$0.03987	$0.01729	**$0.09016**	$0.02479	$ 0.00053	**$0.24040**

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
84	**Very Large Customer Time-Of-Use**																
85	A-4 TOU	Sumr	Fixed Charges	$16.40	$3.00												
86	A-4 TOU	Sumr	Max Demand			$0.00											
87	A-4 TOU	Sumr	On-Pk $//kW & /kWh			$10.00	$0.00	$0.11066	$0.01105	**$0.12171**	$0.03300	$0.12462	$0.01729	**$0.17491**	$0.02479	$ 0.00053	**$0.32194**
88	A-4 TOU	Sumr	Mid-Pk $//kW & /kWh					$0.11066	$0.01105	**$0.12171**	$0.03300	$0.09122	$0.01729	**$0.14151**	$0.02479	$ 0.00053	**$0.28854**
89	A-4 TOU	Sumr	Off-Pk $//kW & /kWh					$0.11066	$0.01105	**$0.12171**	$0.03300	$0.06895	$0.01729	**$0.11924**	$0.02479	$ 0.00053	**$0.26627**
90	A-4 TOU	Wntr	Fixed Charges	$16.40	$3.00												
91	A-4 TOU	Wntr	Max Demand			$0.00											
92	A-4 TOU	Wntr	On-Pk $//kW & /kWh			$10.00	$0.00	$0.11066	$0.01105	**$0.12171**	$0.03300	$0.12462	$0.01729	**$0.17491**	$0.02479	$ 0.00053	**$0.32194**
93	A-4 TOU	Wntr	Mid-Pk $//kW & /kWh					$0.11066	$0.01105	**$0.12171**	$0.03300	$0.09122	$0.01729	**$0.14151**	$0.02479	$ 0.00053	**$0.28854**
94	A-4 TOU	Wntr	Off-Pk $//kW & /kWh					$0.11066	$0.01105	**$0.12171**	$0.03300	$0.06895	$0.01729	**$0.11924**	$0.02479	$ 0.00053	**$0.26627**
95																	
96	A-5 TOU/Sec	Sumr	Fixed Charges	$65.80	$1.50												
97	A-5 TOU/Sec	Sumr	Max Demand			$4.30											
98	A-5 TOU/Sec	Sumr	FIRM BASE On-Pk $//kW & /kWh			$12.38	$4.60										
99	A-5 TOU/Sec	Sumr	NON-FIRM BASE On-Pk $//kW & /kWh			$7.00	$4.60	$0.04760	$0.01105	**$0.05865**	$0.03300	$0.12462	$0.01729	**$0.17491**	$0.02479	$ 0.00053	**$0.25888**
100	A-5 TOU/Sec	Sumr	Mid-Pk $//kW & /kWh			$3.50		$0.04760	$0.01105	**$0.05865**	$0.03300	$0.09122	$0.01729	**$0.14151**	$0.02479	$ 0.00053	**$0.22548**
101	A-5 TOU/Sec	Sumr	Off-Pk $//kW & /kWh					$0.04760	$0.01105	**$0.05865**	$0.03300	$0.06895	$0.01729	**$0.11924**	$0.02479	$ 0.00053	**$0.20321**
102	A-5 TOU/Sec	Wntr	Fixed Charges	$65.80	$1.50												
103	A-5 TOU/Sec	Wntr	Max Demand			$4.30											
104	A-5 TOU/Sec	Wntr	FIRM BASE On-Pk $//kW & /kWh			$12.38	$4.60										
105	A-5 TOU/Sec	Wntr	NON-FIRM BASE On-Pk $//kW & /kWh			$7.00	$4.60	$0.04760	$0.01105	**$0.05865**	$0.03300	$0.06856	$0.01729	**$0.11885**	$0.02479	$ 0.00053	**$0.20282**
106	A-5 TOU/Sec	Wntr	Mid-Pk $//kW & /kWh			$3.50		$0.04760	$0.01105	**$0.05865**	$0.03300	$0.03761	$0.01729	**$0.08790**	$0.02479	$ 0.00053	**$0.17187**
107	A-5 TOU/Sec	Wntr	Off-Pk $//kW & /kWh					$0.04760	$0.01105	**$0.05865**	$0.03300	$0.02421	$0.01729	**$0.07450**	$0.02479	$ 0.00053	**$0.15847**
108																	
109	A-5 TOU/Pri	Sumr	Fixed Charges	$65.80	$1.50												
110	A-5 TOU/Pri	Sumr	Max Demand			$4.30											
111	A-5 TOU/Pri	Sumr	FIRM BASE On-Pk $//kW & /kWh			$12.38	$4.60										
112	A-5 TOU/Pri	Sumr	NON-FIRM BASE On-Pk $//kW & /kWh			$6.00	$4.60	$0.01638	$0.01105	**$0.02743**	$0.03300	$0.06856	$0.01729	**$0.11885**	$0.02479	$ 0.00053	**$0.17160**
113	A-5 TOU/Pri	Sumr	Mid-Pk $//kW & /kWh			$3.50		$0.01638	$0.01105	**$0.02743**	$0.03300	$0.03761	$0.01729	**$0.08790**	$0.02479	$ 0.00053	**$0.14065**
114	A-5 TOU/Pri	Sumr	Off-Pk $//kW & /kWh					$0.01638	$0.01105	**$0.02743**	$0.03300	$0.02421	$0.01729	**$0.07450**	$0.02479	$ 0.00053	**$0.12725**
115	A-5 TOU/Pri	Wntr	Fixed Charges	$65.80	$1.50												
116	A-5 TOU/Pri	Wntr	Max Demand			$4.30											
117	A-5 TOU/Pri	Wntr	FIRM BASE On-Pk $//kW & /kWh			$12.38	$4.60										
118	A-5 TOU/Pri	Wntr	NON-FIRM BASE On-Pk $//kW & /kWh			$6.00	$4.60	$0.01638	$0.01105	**$0.02743**	$0.03300	$0.06657	$0.01729	**$0.11686**	$0.02479	$ 0.00053	**$0.16961**
119	A-5 TOU/Pri	Wntr	Mid-Pk $//kW & /kWh			$3.50		$0.01638	$0.01105	**$0.02743**	$0.03300	$0.03632	$0.01729	**$0.08661**	$0.02479	$ 0.00053	**$0.13936**
120	A-5 TOU/Pri	Wntr	Off-Pk $//kW & /kWh					$0.01638	$0.01105	**$0.02743**	$0.03300	$0.02322	$0.01729	**$0.07351**	$0.02479	$ 0.00053	**$0.12626**

Line #	Rate Schedule	Season	Tier / TOU	Service Chrg $/day	Min. Chrg	Base Demd Chrg $/kW	Supply Demd Chrg $/kW	Base Energy $/kWh	Base Energy Adj $/kWh*	SUBTOTAL Base Rates	Trans $/kWh	PPAC Energy $/kWh	PPAC Adj $/kWh	SUBTOTAL PPAC Rates	All Other Charges**	Regltry Fees $/kWh	TOTAL Energy Chrg
122	**Street Lighting**																
123	SL	Sumr	Customer	$0.21													
124	SL	Sumr	Facilities Charge/Lamp/day	$0.4340													
125	SL	Sumr	Energy Charge					$0.13666	$0.01105	**$0.16306**	$0.03300	$0.03631	$0.01729	**$0.08660**	$0.02479	$ 0.00053	**$0.27498**
126	SL	Wntr	Customer	$0.21													
127	SL	Wntr	Facilities Charge	$0.4340													
128	SL	Wntr	Energy Charge					$0.13666	$0.01105	**$0.16306**	$0.03300	$0.03631	$0.01729	**$0.08660**	$0.02479	$ 0.00053	**$0.27498**
a.	*The "Base Energy Adjustment" is an estimate of the expected BRRAM surcharge. The actual, authorized BRRAM surcharges in effect at the time rates are authorized will be substituted for this placeholder value.																
b.	** The "All Other Charges" is also an estimate of the expected charges. The actual "other" charges in effect at the time rates are authorized will be substituted for this placeholder value.																
c.	Residential Minimum Charge: A minimum charge ($ per day) is applied to the calculation of the total bill will be assessed when the sum of the Service Charge, Base Energy, Transmission Charge, Supply Charge is less than the specified Minimum Charge.																
d.	Non-Residential Minimum Charge: A minimum charge ($ per KW) is applied to the calculation of the total bill will be assessed when the sum of the Base Energy, Base Adjustment, Transmission Charge, Energy Charge, Supply																
	Adjustment Charge and all Demand charges is less than the specified Minimum Charge.																
e.	A-4 Minimum Charge: Will be equal to the Service Charge per meter, per day, plus $1.50 per kW times Contract Demand (New Special Condition 7). New Special Condition 7 indicates "Contract Demand:																
	Is the demand determined, at BVES' option, by an engineering evaluation of the connected load.																

(END OF APPENDIX D)